

**OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION**

MEMORANDUM

April 20, 2015

TO: Phillip Fielder, P.E., Permits and Engineering Group Manager

THROUGH: Phil Martin, P.E., Manager, Existing Source Permits Section

THROUGH: Peer Review

FROM: David Schutz, P.E., New Source Permits Section

SUBJECT: Evaluation of Permit Application No. **2012-1062-C (M-1)(PSD)**
Holly Refining & Marketing (Formerly Sinclair Tulsa Refining Company)
Expansion of Tulsa Refinery (SIC 2911)
East Refinery (FAC ID 1458)
902 W. 25th Street, Tulsa, Tulsa County (36.126°N, 96.002°W)
Portions of Sections 13, 14 and 23, T19N, R12E

I. INTRODUCTION

Holly Refining & Marketing (HRMT) and Holly Energy Partners (HEP) operate the Tulsa Refinery and product loading terminal under three separate permits:

- The HRMT West Refinery is under Part 70 Permit No. 2010-599-TVR (M-1), issued January 2, 2014.
- The HRMT East Refinery is under Part 70 Permit No. 2012-1062-TVR2 (M-2), issued September 17, 2014. The loading terminal and tank farms operated by HEP are under Part 70 Permit No. 2012-924-TV (M-2), issued June 11, 2014.

The two refineries owned by HRMT were acquired at separate times, therefore, are permitted separately. The loading terminal is owned and operated by HEP, resulting in another separate permit for it. However, the two refineries and loading terminal are interconnected and collocated, requiring that they be treated as a single facility when conducting a PSD analysis. For the purpose of the PSD analysis only, HRMT and HEP together are at times referred to as “Holly.”

HRMT and HEP propose a construction project to expand the refineries and loading terminals. The project will commence in the 2014-2015 time frame. There will be new process units added and modification of existing process units such that the total capacities of the refineries will be increased to 170,000 BPD from the current capacity of 160,000 BPD. There will be “associated” emissions increases from most units in the refinery, excepting those emissions units which are independent of unit process rates such as emergency engines, fugitive VOC leakage from valves, flanges, etc.

The net emissions change analysis applies to all three, and all PSD analyses other than BACT will encompass all three facilities. The BACT analysis in this permit will be limited to the types of units being added to the East Refinery.

Over the previous 5 years, there have been multiple construction projects which were subject either to PSD review or to requirements to keep records of actual emissions to show that the difference between Baseline Actual Emissions and Actual Emissions did not exceed PSD levels of significance. Those permits will be superseded by this construction permit, incorporating those preceding changes as part of the “net emissions changes” in the PSD netting analysis.

The proposed project is subject to Prevention of Significant Deterioration (PSD) review for added emissions of greenhouse gases (GHG), carbon monoxide (CO), nitrogen oxides (NO_x), and particulate matter (PM₁₀ / PM_{2.5}). Full PSD review consists of:

- A. determination of best available control technology (BACT)
- B. evaluation of existing air quality and determination of monitoring requirements
- C. evaluation of PSD increment consumption
- D. analysis of compliance with National Ambient Air Quality Standards (NAAQS)
- E. ambient air monitoring
- F. evaluation of source-related impacts on growth, soils, vegetation, visibility
- G. evaluation of Class I area impacts.

The refinery will accept NSPS Subpart Ja limits on SO₂ emissions on all fuel gas combustion devices to net out from PSD for SO₂. The Projected Actual Emissions from selected, existing fuel gas combustion devices were based on 25 ppm H₂S in refinery fuel gas.

II. FACILITY DESCRIPTION

The East Refinery is a fuels refinery with several major process units. Other activities include various minor processes outside the major units, including storage and transfer of products. Much of the equipment was placed in service before the promulgation of permitting requirements. The oldest construction dates from approximately 1907, when the Texas Company commenced building in the area. Sinclair purchased the facility from Texaco in 1983, and then HRMT purchased the refinery in 2009. Refinery property covers approximately 470 acres.

Refining is a complex process to make crude oil into a variety of products, including gasoline, heating oil, lubricants, and feedstocks for other industries. Refining equipment and processes involve a certain amount of iterative treatment, in which materials may be processed more than once at a particular location or may be returned to an earlier step in the system for further handling. Only those processes necessary to understand the basic principles are presented.

A very general description of the entire process at this particular refinery starts with crude oil being processed in the Crude Unit. Process streams flow from the Crude Unit to the Fluid Catalytic Cracking Unit (FCCU), the Distillate Hydrotreating Unit (DHTU), Naphtha Hydrodesulfurization Unit (NHDS), and the Unifiner/Penex (Penex). A residual stream currently becomes asphalt or residual fuel oil; in the near future, that residual stream is planned to be processed for extraction of gas oil and asphaltene feedstocks. Tulsa Refinery primary products are classified as gasoline, distillate, residual fuel oil, and asphalt, but there are also ancillary products, such as propane, butane, propylene, and sulfur.

Note that Emission Unit Groups (EUGs) are based on different criteria from those used to describe process units, so descriptions of the EUGs do not match those of the processing units. For example, EUG #9 consists of heaters found in three different units. Similarly, the storage tanks are divided into EUGs based on roof design and permit status.

A. Crude Distillation Unit (CDU)

Distillation is a thermal process that separates product fractions out of a mix of materials based on differences in boiling points. The CDU separates crude oil into intermediate products, which are either feedstocks for downstream units or residual products. Sour crude, defined by HRMT as crude oil with sulfur content greater than 0.5% by weight, represents approximately 10% of all volume processed by this unit. The remaining 90% sweet crude at the Tulsa refinery has historically averaged approximately 0.4% by weight sulfur.

Crude oil is currently brought to the refinery by pipeline. Sweet and sour crude are segregated in storage tanks and are processed in separate batches through the CDU. All crude is de-salted before entering the distillation towers to remove chlorides that would be damaging to piping and vessels. Sweet crude is usually injected into sour crude runs. There are fugitive emissions from the CDU. The only point source is a common stack serving two heaters. These gas-fired heaters serve the atmospheric distillation tower and the vacuum distillation tower (EUG 9, Point ID 6155). Crude flows through the atmospheric tower first, where the lighter ends are removed or distilled. "Atmospheric" simply refers to the fact that the constituents distilled in the tower are capable of vaporizing at atmospheric pressure. Heavier ends that are not distilled in this tower are then run through the vacuum tower for further separation. A vacuum is achieved in the vacuum tower through use of three stages of steam ejectors. Condensers remove condensable vapors to the greatest extent possible after each of the ejectors. The vent gas flows to the wet gas compressor (J-50) within the FCCU or into the flare system if J-50 is not operating. Some material is refluxed, meaning that it is taken out of the column and reintroduced at an earlier point to achieve better separation into distinct product fractions. Refluxing is also a method for taking heat out of the tower. It is one of the processes that is used at different points and that constitutes one of the techniques to improve performance and more efficiently process materials in the CDU. The proposed project involves modification of the CDU Atmospheric Tower Heater from 200 to 248 MMBTUH capacity which will allow throughput to increase from 63,000 BPD to 70,000 BPD.

HRMT defines eight outputs from the CDU in order of increasing molecular weight as follows. Numbers 1 - 6 come from the atmospheric tower, while 7 and 8 come from the vacuum tower.

1. Light ends. This stream is methane and ethane and goes to the FCCU wet gas scrubber.
2. Butane/propane. This stream goes to the DHTU.
3. Light straight run. This is mostly C₅ material and goes to Penex.
4. Naphtha. This material goes to the NHDS.
5. Kerosene. This goes to the DHTU.
6. Light atmospheric gas oil. This goes to the DHTU.
7. Gas oils. These go to the FCCU.
8. Vacuum resid. This is the residual material or “bottoms” remaining after all other outputs have been captured. Resid currently goes directly for sale as asphalt or roofing flux. (There are no asphalt blowstills or other oxidation processes utilized at the Tulsa Refinery.) Part of the expansion is installation of “ROSE” Unit to process resid into asphaltenes and “gas oil” feed to the FCCU.

The facility refers to the sour bottoms as asphalt and to all other material as “flux.” Intermediate storage for both materials is in heated tanks.

Personnel operating the CDU are also responsible for managing butane truck loading and unloading (EU 22, Point ID 6171).

B. Fluid Catalytic Cracking Unit (FCCU)

The FCCU treats gas oils from the CDU with heat in the presence of a catalyst. Generally, hot gas oil from sweet crudes is mixed with cold gas oil from sour crudes, and the situation is reversed when sour crude is being processed. The FCCU has current capacity estimated at 24,000 BPD with a maximum anticipated processing rate of 28,400 BPD. “Gas oils” are heavier than diesel and lighter than the residual products taken from the CDU. Heavy molecules are broken or “cracked” into lighter molecules that allow the facility to increase the production of liquid fuels. A distillation tower then separates these products into gasoline and diesel components, as well as producing feedstock for the Alkylation (ALKY) and Scanfiner (SCAN) Units.

FCCU catalyst is regenerated continuously to prevent coke build-up, with sufficient catalyst added daily to maintain a relatively constant inventory and level of catalytic activity. Spent catalyst is removed from the regenerator every few days and stored for sale to other refiners or catalyst brokers. This catalyst is valuable and various devices control potential air emissions of it, to minimize its loss. The first set of these devices consists of cyclones in the reaction vessel. In addition, the regenerator contains five three-stage cyclones. The electrostatic precipitator (ESP) on the FCCU stack has been replaced by a wet gas scrubber (WGS). Salts and particulates removed by the WGS are shipped offsite for disposal, while the liquid will be sent to the oily wastewater collection system. A selective catalytic reduction (SCR) system has been added to control NO_x emissions. Installation of the SCR required the addition of a 20,000-gallon tank for aqueous ammonia and two 6,400-gallon tanks for sodium hydroxide. The aqueous ammonia is an ammonium hydroxide solution with less than 20% concentration of ammonia. Carbon monoxide emissions from the regenerator are minimized through complete combustion by

controlling the excess oxygen content in the flue gas. The FCCU is very difficult to shut down and start up due to the high temperatures involved and the volume of catalyst circulating through it. These activities are managed and tracked through the facility's startup, shutdown, and malfunction plan (SSMP).

Similar to the handling of crude in the CDU, products of this cracking process are distilled thermally in the tower. Heavy ends, or tower "bottoms," are known as decanted oil. Light ends from this unit and gasses from the CDU are compressed and run through an absorber at the FCCU. Any remaining gas becomes part of the refinery fuel gas system. A set of electrically-driven compressors is used to compress and circulate the unit gas for further processing. These compressors are often called the "wet gas compressors."

A gas-fired charge heater (B-2) supplies heat for current operation of the FCCU. Heat to perform the function of this reboiler is now taken from the fractionator slurry bottoms. A gas-fired air heater (B-1) is used only during FCCU startup. A gas-fired steam superheater has been idle since 1996. Heat previously supplied by the superheater is now obtained from B-2.

Propylene loading of railcars (3-spot) and trucks (1-spot) is functionally connected to the FCCU. Additionally, the FCCU is responsible for the operation of two flares, all pressurized spheres, and all pressurized "bullet" tanks except for three tanks located at the ALKY Unit. The CDU, FCCU, ALKY, POLY, and PENEX Units feed flare #1. Everything else is directed to Flare #2. During normal refinery operation, both flares feed into a common header and are directed to the flare gas recovery unit.

Part of the expansion project is improvement to the FCCU, replacing the reactor, riser, and feed nozzles with modern designs. Modern equipment is expected to maximize product yield and reduce coke generation, the source of air emissions. Despite the increased throughput, emissions are not projected to increase.

C. Unifiner/Penex Unit (PENEX)

PENEX is a process that was installed at the ISOM (Isomerization) Unit in 2002. The ISOM was commissioned in 1987 by modifying a catalytic reforming unit (CRU) that had been idle for a long period. The PENEX upgrades the octane of light straight run naphtha from the CDU by isomerizing the normal pentanes to isopentanes. The PENEX also saturates benzene, thus reducing the benzene and aromatic levels in gasoline produced by HRMT. Light straight run naphtha from the CDU is sent to intermediate storage before it is charged to the PENEX. PENEX contains two reactors that can be operated independently. Catalyst in these reactors has an optimal life of seven years and is reclaimed, but not regenerated. The charge is first treated by the Unifiner reactor to remove sulfur and nitrogen. This is a catalytic process that requires hydrogen from the CCR (see below) to combine with the elemental sulfur stripped out of various compounds, such as mercaptans. The hydrogen sulfide thus formed can be stripped out of the stream and sent for processing at the SRU (see below). Unifiner catalyst is long-lived and normally does not require regeneration.

Products from the PENEX are normally sent to intermediate storage as gasoline blending components but can also be blended directly into gasoline. Offgas produced is run through an absorption process before being sent to the fuel gas system. The absorber is light cycle oil from the FCCU. Heavier constituents of the offgas are absorbed by the oil and sent to the FCCU fractionator, while the lighter ends are used as fuel gas. The Unifiner section has a charge heater and stack (EUG 9, Point ID 6167). The normal charge rate to the PENEX is approximately 6,000 BPD although it has nominal capacity to charge over 8,500 BPD.

D. Continuous Catalytic Reforming Unit (CCR)

The CCR upgrades the octane of heavy straight run naphtha from the CDU (through the NHDS) by dehydrogenating the hydrocarbons, resulting in the production of high octane materials such as aromatics. These high octane “blend stocks” are blended directly into gasoline. This stream is one of the most important components of premium grades of gasoline. HRMT’s reforming process is also called “platforming,” because it uses a platinum catalyst in three reactors. The catalyst is fouled quickly by sulfur, so only sweet naphtha feedstock from the NHDS may be used. This process had been performed by the catalytic reforming unit (CRU), which was modified under Permit No. 98-021-C (M-26) to create the CCR. The existing unit was converted into a CCR capable of processing approximately 22,000 BPD of desulfurized naphtha from the NHDS. Three new reactors hold approximately 100 tons of catalyst and circulate 1,000 pounds of catalyst through the regenerator per hour. Catalyst flows down through each reactor, dropping from each reactor to the next. As the catalyst exits the bottom of the third reactor, a countercurrent flow of hydrogen purges hydrocarbon back into the third reactor. Nitrogen then carries the catalyst to filter media at the top of the regenerator structure, where fines are removed from the catalyst before it flows to a disengaging hopper.

The “disengaging” term used here means that this is the point at which the catalyst is no longer borne by the nitrogen; it is “disengaged” or separated from the nitrogen transportation medium. Approximately 5-10 pounds of fines are expected to be removed daily and sent for offsite reclamation. The catalyst is cooled to 250-300°F in the disengaging hopper, and is then dropped into the regenerator. The regenerator has three zones, identified as the diluted air zone, the oxychlorination zone, and the drying zone. Approximately 0.07 mol% oxygen is reacted with the catalyst to begin coke burn-off in the diluted air zone. The low oxygen content and the name of the zone are derived from diluting air with nitrogen. The catalyst then drops to the oxychlorination zone, where it is reacted with air and perchloroethylene (perc), which conditions the catalyst by redistributing the metal on the catalyst. Air is blown across the catalyst in the drying zone to remove any remaining moisture. The regenerated catalyst exits the bottom of the regenerator and is moved with hydrogen to the reduction zone above the top of the first reactor. At this point it is further regenerated by contact with additional hydrogen, which combines with excess oxygen to create water vapor. During reactor operation, chloride is injected into the reactor to help maintain catalyst activity. The regenerator tower vents back through the disengaging hopper, allowing the sulfur and chloride in the regenerator vent gas to be absorbed by the catalyst entering the regenerator. This reabsorption process is known as Chlorisorb. Platforming produces hydrogen that is then used by the NHDS, DHTU, SCAN, and PENEX units for desulfurization of their feedstocks, although some of the hydrogen is retained or recycled in the reactors to prevent the reaction from cracking the naphtha. The CCR had first operations on December 11, 2007.

There are five heaters associated with this unit. A 155 MMBTUH heater, identified as the #1 Interheater (10H-113), is described in EUG 26. One stack serves the 101 MMBTUH Interheater #2-1, the 25 MMBTUH Interheater #2-2, and the 120 MMBTUH charge heater, and is identified as Point ID 6163 in EUG 27. The 85 MMBTUH stabilizer reboiler heater is identified as Point ID 6162 of EUG 27. The newer 155 MMBTUH heater was installed with low-NO_x burners and the 120 and 85 MMBTUH heaters have been retrofitted with low-NO_x equipment.

Part of the proposed expansion project is installing an additional 25 MMBTUH heater at the CCR Unit.

E. Naphtha Hydrodesulfurizer Unit (NHDS)

The NHDS removes sulfur from the CCR charge (heavy straight run naphtha). The sulfur removal process is catalytic and requires hydrogen, which is supplied by the CCR. The interdependence of this unit and the CCR requires that sufficient sweet material produced by the NHDS be stored to provide for a startup of the CCR. Sulfur is removed in the form of H₂S. Most of the offgas from this unit is recycled, with excess gas being amine-treated before going to the fuel gas system. Hydrogen is injected in several places and a large part of the unit has two-phase flow. Some of the hydrogen passes through the system and is being continually recovered, compressed, and recycled. The NHDS is normally shut down every three to four years for maintenance, based on catalyst life. The catalyst is not normally regenerated and is replaced every few years. Spent catalyst is sent off site for either regeneration or metals reclamation and disposal. This unit had first operations on March 20, 2006. A pre-modification capacity of 22,000 BPD was stated for this unit.

There are two heaters with low-NO_x burners at this unit. A 39 MMBTUH charge heater and a 44.2 MMBTUH stripper reboiler heater are both described in EUG 25. Part of the proposed expansion is installing an additional 10 MMBTUH heater at the NHDS Unit.

F. Distillate Hydrotreating Unit (DHTU)

The old naphtha/distillate HTU was converted to a DHTU capable of processing approximately 24,000 barrels per day (BPD) in 2006. Conversion included new internals in the reactor, such as reducing the number of catalyst beds, using a new catalyst, and redesigning the quench nozzles. There are several new vessels, including a high pressure separator, a new amine treater, a coalescer, a salt tower, and various air and water coolers. The existing HTU charge heater remains in service as the DHTU charge heater, but the stripper reboiler heater was permanently removed in 2006. First operations at the DHTU occurred May 25, 2006. The refinery interconnection increased the capacity to 40,000 BPD, and the proposed project will further increase capacity to approximately 45,000 BPD.

The DHTU removes sulfur from diesel blend stocks. Both #1 and #2 diesel streams are treated in the DHTU. Naphtha is treated by the NHDS (see E above). The DHTU normally treats distillate streams from the field or hot from the CDU or the FCCU. Gases from this unit are treated before going to the fuel gas system. The DHTU is normally shut down every three to four years for maintenance, based on catalyst life. The catalyst is not normally regenerated and is replaced every few years. The catalyst is sent off site for either regeneration or metals reclamation and disposal. The DHTU is dependent on the CCR for hydrogen. The DHTU is also responsible for the Light Hydrocarbon Treating Unit (LHC) which treats light hydrocarbon streams to remove hydrogen sulfide.

There are currently two emission points associated with this unit; one active and one inactive. The charge heater stack is Point 6157 in EUG 27. The other stack is Point ID 6156 (was in EUG 9) common for both the splitter and fractionator reboiler heaters, both of which were idled as part of the conversion of the old HTU to the DHTU. Part of the proposed expansion is installing an additional 50 MMBTUH heater at the DHTU Unit.

G. Alkylation Unit (ALKY)

Alkylation is a process that creates large molecules by reacting two shorter molecules in the presence of a catalyst. In this case, the alkylate produced is typically high-octane material necessary for blend stock. Debutanizer net overhead from the FCCU is rich in butenes and serves as ALKY feedstock. The feed is pre-treated by the POLY. Treated feed first passes through a deethanizer. Light ends are sent to the fuel gas system and the feed is sent to the propylene splitter at the POLY unit, as described in Item "H" following. The remaining olefin feed, consisting mostly of butenes, is returned to ALKY to be reacted with isobutanes using sulfuric acid as a catalyst to produce the alkylate. The process uses isobutanes greatly in excess of the stoichiometric amount, so the alkylate is fed through three more towers, those being the depropanizer, deisobutanizer and debutanizer. Historically, approximately 3,500 BPD of alkylate has been produced. The facility accepted a limit of 5,500 BPD to avoid PSD consideration under Permit No. 98-021-C, issued October 18, 2000; that limit is being relaxed to 6,500 BPD in this permit. The ALKY receives sulfuric acid and stores it for use. It also sends spent acid for regeneration. Sulfuric acid is loaded from and unloaded to trailers at the ALKY, and can also be received from and loaded into rail cars. ALKY personnel are also responsible for three pressurized bullet tanks, Nos. 58, 59, and 60, located on the unit (EUG 22, Point ID 6288 through 6290). One of these tanks holds butane, a second holds isobutane, and the third is a surge tank used for emergency service. There are no point sources associated with this unit.

H. Poly Pretreat Unit (POLY)

This area of the refinery was originally a polymerization unit, hence the name POLY. Most of the unit has been idle since some time prior to HRMT's purchase of the refinery, but some pieces of equipment have been used for other purposes. Feed for the ALKY unit is treated by the POLY to remove sulfur and any other impurities that might harm the catalyst or otherwise disturb the reaction. An amine system removes hydrogen sulfide, caustic solution removes residual hydrogen sulfide and mercaptan sulfur, and a water wash removes basic nitrogen compounds. A propene recovery system, often referred to as the propylene splitter, was started at the POLY unit in 1996. Approximately 600 BPD of propene have been recovered, stored, and sold as a product in the past. POLY is estimated to have average capacity of 4,000 BPD. There are no point sources associated with this unit.

I. Scanfiner (SCAN)

The SCAN process takes all or a portion of naphtha (often referred to as "cat naphtha" or "cat gasoline") from the fluid catalytic cracking unit (FCCU) and removes the sulfur. The first stage of the process, the diolefin saturator, is designed to convert diolefins into olefins without beginning hydrodesulfurization or olefin saturation. Diolefins need to be removed as they can cause significant fouling in the process equipment.

After diolefin saturation, the cat naphtha is fed into the main SCAN reactor, where hydrodesulfurization, hydrodenitrogenation, and olefin saturation reactions occur over a catalyst. The main product from this reactor is low sulfur cat naphtha, which is a key blend component in producing low sulfur gasoline blends. The process consumes hydrogen and also recovers hydrogen, hydrogen sulfide, and ammonia. The product stream is cooled and water washed prior to entering the reactor effluent separator. Water wash helps prevent chloride build-up in the equipment, and the water is reused to the greatest extent possible through the system. A minimal amount of water is sent to the refinery wastewater system to maintain wash water quality. The hydrogen from the reactor effluent separator, called recycle gas, is sent to an amine absorber in the SCAN unit where the hydrogen sulfide is removed. A small portion of the recycle gas is purged to the fuel gas system to maintain adequate hydrogen purity and makeup hydrogen is fed into the recycle gas upstream of the amine absorber. The recycle gas is then compressed and sent back to the reactor section. Liquid hydrocarbon from the separator is sent to the product stripper, where light ends (butane and higher) and hydrogen sulfide are removed. The non-condensable gas stream (hydrogen, hydrogen sulfide, ammonia) from the separator is sent to an existing amine absorber where it is amine scrubbed for hydrogen sulfide removal prior to injection into the fuel gas system. Low sulfur gasoline from the product stripper is sent to gasoline blending after cooling. ARU (Amine Regeneration Unit) #1 processes the sour amine solution from the amine absorber. Acid gas from the ARU is vented to the sulfur recovery units (SRU#1 and/or SRU#2).

The hydrogen utilized in the SCAN process is obtained from the excess hydrogen produced by other process equipment. This hydrogen would otherwise be blended into the refinery fuel gas system and used to fire the various process heaters and boilers at the refinery. While the SCAN process generates a small quantity of fuel gas, any additional fuel gas demand at the refinery created by removal of the hydrogen from the fuel gas system is satisfied by purchasing natural gas. First operations of the Scanfiner unit occurred December 17, 2004.

J. Sulfur Recovery Units (SRU #1/ SRU #2)

The SRUs recover sulfur from acid gas streams and sour water stripper overhead and store it in elemental form for sale. The refinery currently has an amine system that removes H_2S from various gas and liquid hydrocarbon streams. There are six amine treaters (or “contactors”) that contact the different streams with lean amine, where “lean” means that the amine has a low concentration of H_2S . The lean amine absorbs the H_2S , making it into a “rich,” or high-concentration, stream. The ARU regenerates the amine solution by boiling it, producing lean amine to return to the contactors and hydrogen sulfide to feed the SRU. The SRUs use the Claus process. One third of the H_2S is oxidized to form SO_2 and the SO_2 is reacted with the remaining H_2S in the presence of an alumina catalyst to form elemental sulfur and water vapor. The liquid sulfur is stored in a pit for shipping by rail or truck. The reaction does not achieve total removal of sulfur (manufacturer’s guarantee is 99.5%) so the tail gas is scrubbed by Tail Gas Treating Units (TGTU) to recover most remaining sulfur oxides formed before they are released from the stack (EUG 10, Point ID 6152). The TGTUs incinerate remaining H_2S to SO_2 , which is then removed by a following caustic scrubber. Scrubber waste products are routed to the wastewater treatment system. Tail gas concentration of SO_2 is maintained below 250 ppm on a 12-hour rolling average. Continuous emission monitors (CEMs) on both SRUs demonstrate compliance. SRU #2 had first operation on June 1, 2006.

The Sour Water Stripper (SWS) is also associated with this complex of units. The SWS takes sour water from various units and removes ammonia and H_2S . Modifications to the SWS in 2006 replaced the trays, increased the operating pressure of the stripper, and installed a new feed-to-bottoms heat exchanger. These changes increased the capacity to approximately 190 gpm. Offgas from SWS is sent to SRU #2, because SRU #1 has proven incapable of handling this material without fouling of the catalyst. If SRU #2 is unavailable for some reason, SWS will be placed on fresh water feed or shut down and sour water stored in tanks. Upon return to service of SRU #2, any accumulated sour water will be processed and the offgas sent to SRU #2.

The design capacities of SRU #1 and SRU #2 are each 25 long tons per day (LTPD).

K. ROSE Unit

A new ROSE Unit will be constructed at the East Refinery. Residuum Oil Supercritical Extraction (ROSE) is a process where a light, condensable hydrocarbon such as liquid propane or isobutene is used to treat the “residuum oil,” or bottoms from the vacuum distillation unit. Residuum contains a mixture of heavy oils from which FCCU feed (“gas oil”) can be separated from asphaltenes. The process mixes the light hydrocarbon with the residuum, extracting the gas oil from the asphaltenes. Asphaltenes are processed off-site to produce road and roofing asphalt, and the light hydrocarbon is evaporated out from the gas oil. The light hydrocarbons are condensed back to liquids then recycled to the process.

L. Boiler House (BOHO)

The BOHO is responsible for steam production for the refinery. The BOHO is also responsible for the other utility systems such as plant air, instrument air, and nitrogen. There are four existing boilers at the BOHO, each capable of producing over 100,000 pounds per hour of 250 psig steam. These boilers primarily burn sweet plant fuel gas. Although each boiler is also capable of burning liquid fuel, the piping to facilitate liquid fuel burning has been removed. Generally, a different boiler is shut down every six months for maintenance. The Consent Decree (CD) required that each boiler have its own stack and that each boiler be subject to NO_x control. Now there are selective catalytic reduction (SCR) systems on all four boilers. Continuous emission monitoring systems (CEMS) have been installed on each stack. These are the only emission points associated with the BOHO.

M. Wastewater Treatment Plant (WWTP)

The Wastewater Treatment System collects and treats wastewater generated in the refinery prior to discharging water to the Arkansas River, including both process generated wastewater and storm water. Both federal and state agencies regulate the effluent going to the river. Federal requirements are under the jurisdiction of the Environmental Protection Agency (EPA) and are covered by the National Pollutant Discharge Elimination System (NPDES). State requirements are under the jurisdiction of the Oklahoma Department of Environmental Quality (ODEQ) and are covered by the Oklahoma State Discharge Permit System (OSDPS). Various federal standards govern wastewater operations, including 40 CFR 60 (NSPS) Subpart QQQ (VOC Emissions from Petroleum Refinery Wastewater Systems), 40 CFR 61 (NESHAP) Subpart FF (Benzene Waste Operations NESHAP [BWON]), and 40 CFR 63 (MACT) Subpart CC (Petroleum Refineries).

There are five sewer systems, three of which handle oily (process) wastewater and two of which handle (non-process) storm water. Storm water systems are not subject to NSPS Subpart QQQ. Each of the five systems is described as follows.

- Uncontrolled refinery individual drain system (IDS) and uncontrolled API separator tanks.
- IDS and API separator tank(s) controlled by BWON. The IDS and API tank(s) were installed in 2005.
- Refinery slop oil system, in which tankage is designed with BWON-compliant controls.
- A storm water collection system that ties into the first common junction box of the uncontrolled refinery IDS. This system collects storm water from concrete pads and areas within unit limits (on-unit).
- A storm sewer system that collects storm water from outside the process unit battery limits (off-unit) and routes it to the off-unit storm pond. The pond holds approximately 33 million gallons of this water that is normally used for cooling tower makeup water, although it can be discharged to the Arkansas River.

HRMT currently purchases approximately 3 million gallons of additional municipal water daily to make up for process use.

The first four systems are all routed to the WWTP. Water entering the WWTP is tested for various impurities at the diversion box. Material with certain levels of impurities is sent to the off-test tank, from which it is later blended back into the treatment system. The water then passes through either of two API separators, with any skimmed hydrocarbon going to a slop oil tank. Water continues to the equalization basin, where it is stirred and aerated and microbial action begins to digest the hydrocarbons. A bio-disk unit continues the digestion process with more “bugs.” Clarifiers separate the dead microorganisms and any other solids from the water for further processing in a digester. Upgrades to the aeration basin and clarifiers were made in 2001 and 2003. Biological material wasted from this process is used as fertilizer to maintain vegetative cover on the facility’s two closed land treatment units. Remaining water goes to the Final Pond, where it is tested before discharging to the Arkansas River or being used to irrigate the refinery’s two closed land treatment units. A large pond and two tanks are available as storage for rain that falls on the process units. Tank 477 with a nominal capacity of 5,031 bbls was constructed in conjunction with Permit No. 98-021-AD (M-37) and acts a wide spot in the line to slow storm surge flow from the NHDS and SRU#2 units. On-unit storm water from tank 477 travels through an uncontrolled IDS and then through tank 476 to the equalization basin. Tank 459 with a nominal capacity of 80,000 bbls has been repurposed from EUG 1 (MACT CC Group 1 Storage Vessels) to storm water surge storage as described in Permit Nos. 98-021-TV (M-50) and 2007-005-AD (M-4). Storm water can be pumped from the on-unit storm water pond to tank 459 and back again as needed for containment. Various water treating chemicals including hydrogen peroxide are used in treating wastewater. Fugitive emissions from the Wastewater Treatment System are included with Equipment Leaks - Process Units.

N. Miscellaneous Points

Miscellaneous equipment leaks or fugitive emissions occur from all piping components throughout the refinery. These emissions are estimated with AP-42 factors and there are two points associated with fugitive emissions. The Hydrocarbon Recovery System consists of an ongoing effort to recover oil from beneath the refinery. It consists of several wells, separators, and storage tanks or batteries scattered throughout the refinery. This equipment is moved as necessary to maximize the recovery of oil. The hydrocarbon recovery system has small emissions, but cannot qualify as an insignificant activity because it is subject to 40 CFR 63 Subpart GGGGG (EUG 18). There are several cooling towers that serve the refinery. The cooling towers are treated using sodium hypochlorite.

A fuel system using light ends from various processes to feed combustion devices is known as the refinery fuel gas system and the rich gas it carries is frequently called RFG. Fugitive emissions from the RFG system are calculated and listed with other fugitives from each unit.

As noted in the introduction, oldest parts of the facility date from 1907. Some of the equipment at the facility was constructed before state or federal air pollution rules and regulations were promulgated, and many of these sources are grandfathered (exempt from permit requirements). DEQ or a predecessor agency has permitted various pieces of equipment. A list of those permits was contained in the memorandum associated with the initial TV permit. Other environmental permits include RCRA Post Closure for the Flare Area Treatment Unit (EPA No. 990750960-PC) and NPDES wastewater discharge (EPA No. OK0001309 / DEQ No. I72001630).

SECTION III. PROPOSED PROJECT DESCRIPTIONS

The proposed projects for each facility are listed following. The new and modified units are categorized as combustion units (heaters); process units with fugitive VOC leakage from valves, flanges, etc.; the Fluid Catalytic Cracking Unit (FCCU); the Continuous Catalyst Regenerator serving the Platformer Unit; and storage tanks.

East Refinery

- A new 10,000 BPCD Liquid Petroleum Gas (LPG) Recovery Unit charging 32 MMSCFD gas;
- A new 10,000 BPCD Residuum Oil Supercritical Extraction (ROSE) Unit with a new 42 MMBTUH HHV heater;
- Expanded Diesel Hydrotreater Unit (DHTU), with a new 50 MMBTUH HHV helper heater;
- Revamped FCCU, increasing process throughput from 24,000 BPCD to capacity of approximately 28,400 BPCD;
- Modified Naphtha Hydrodesulfurizer (NHDS) Unit, with a new 10 MMBTUH HHV helper heater;
- Modified Continuous Catalytic Reforming (CCR) Unit, with a new 25 MMBTUH HHV helper heater;
- A new Naphtha Fractionation Column which will require steam from facility boilers;
- Expansion of the Alkylation (ALKY) Unit to 6,500 BPD, using steam from existing boilers for process heat.
- The CDU Atmospheric Tower Heater will be modified from 200 MMBTUH capacity to 248 MMBTUH capacity.
- New tanks will be added to the East Refinery, but the final designs are not yet ready. As an interim measure, a limit of 1.24 TPY VOC from the new tanks will be established.

West Refinery

- Propane Deasphalter (PDA) Unit revamp and modification to become a Residuum Oil Supercritical Extraction (ROSE) Unit, with a new 76 MMBTUH HHV heater; and
- A new 10 MMSCFD Hydrogen (H₂) Plant will be constructed, with a reformer heater sized at 125 MMBTUH. The heater will be fueled with natural gas or refinery fuel gas, which may include Pressure Swing Absorption (PSA) off-gas.
- New tanks will be added to the West Refinery, but the final designs are not yet ready. As an interim measure, a limit of 26.69 TPY VOC from the new tanks will be established.

HEP (Loading Terminal and Storage)

- A new 90,000 BPCD Inline Gasoline Blender.
- A new Propane Loading Unit will replace the existing Propane Loading Unit.
- Construction of new tanks with VOC emissions up to 22.1 TPY will be authorized, but specifications for the new tanks are not yet known.

IV. EQUIPMENT

Tank identifiers include a facility-wide “Tank No.” and a “Point ID” used in annual emission inventories. Tank capacities are all stated in barrels. Various tanks have been moved from one EUG to another. Since several units have been moved to another permit, there will be gaps in the sequence of EUGs. Most refinery units contain numerous vessels and myriad valves and connectors. Only the emission points are identified in the following descriptions.

The four new heaters are in EUG-29. The modified CCR #1 Interheater (10H-113) will remain in EUG-26; as the only unit in that EUG, applicability will be changed from NSPS Subpart J to NSPS Subpart Ja. The modified CDU Atmospheric Tower Heater will be moved by itself into EUG-33.

The modified CCR Unit will remain by itself in EUG-6. The FCCU will also remain by itself in EUG-11.

The new LPG Recovery Unit will be in EUG-28 and the new ROSE Unit will be in EUG-30. Both will be subject to NSPS Subpart GGGa.

The new Naphtha Fractionation Column will be a separate new process unit in EUG-32, subject to NSPS Subpart GGGa.

The modified DHTU and NHDS units will be in EUG-32. Both become subject to NSPS Subpart GGGa upon modification.

The modified Alky units will be in EUG-32. That unit becomes subject to NSPS Subpart GGGa upon modification.

New process drains at the Naphtha Fractionator Column and ROSE unit will be in EUG-17 due to overlap provisions of MACT Subpart CC.

EUG 3 MACT CC Group 2 Storage Vessels - Fixed Roof (FR)

These storage vessels are regulated under 40 CFR Part 60, Subpart UU and 40 CFR 63 Subpart CC (MACT CC) Group 2 Storage Vessels and are limited to the existing equipment as it is. Due to the overlap provisions of MACT CC (§63.640(n)), this list includes any Group 2 storage vessels that are also regulated under NSPS Subparts K or Ka but that are not required to meet the K/Ka control standards, as they must meet the MACT requirements per §63.640(n)(7). Storage vessels required to meet control requirements under NSPS Subparts K and Ka are required to comply only with those subparts, per §63.640(n)(6), and are not included in this list.

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
112	6195	2012	30'	110'	50,000
118	6201	1907	30'	96'	37,500
119	6202	1907	30'	96'	37,500
126	6263	1907	30'	96'	37,500

EUG 4 MACT CC Wastewater Tanks

These storage vessels are regulated under 40 CFR 63 Subpart CC (MACT CC) as wastewater management units and are limited to the existing equipment as it is. Due to the overlap provisions of MACT CC, the requirements of 40 CFR 61 Subpart FF (BWON), and 40 CFR 60 Subpart QQQ (NSPS QQQ), these vessels are required to comply with Subpart FF to meet the applicable standards under MACT CC, BWON, and NSPS QQQ.

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
13	6243	1976	40'	116'	75,250
400	17035	1922	30'	24'	2,400
401	17036	1920	20'	25'	1,700

¹ Originally Kb tanks, converted to wastewater only.

EUG 6 Continuous Catalytic Reforming Unit (CCR)

The CCR is regulated by 40 CFR 63 Subpart UUU, and is limited to inorganic HAP of 10 ppmvd corrected to 3% oxygen at the regenerator stack. The facility complies with VOHAP standards by venting organic materials to the flare system.

EUG 8 Fired Boilers

Each boiler exhausts approximately maximum 76,000 acfm at an estimated 300°F from a 72" diameter stack at 60' above grade. Listed heat capacities are based on boilerplate capacity of 170,000 pounds/hour of 350 psi, 500°F steam. There were no emission limits applied to this EUG under Title V but it was limited to the existing equipment as it is. Per the CD, the boilers became subject to NSPS Subpart J effective June 30, 2008, and became subject to NO_x emissions limits. HRMT has taken a voluntary limit equal to NSPS Subpart Ja; SO₂ emissions will be subject to the limit. Each boiler is fitted with SCR for control of NO_x and compliance is monitored by CEMs.

ID	Point ID	Name/Model	Heat Capacity	Construction Date
1	6150	Babcock & Wilcox FH 26	233 MMBTUH	1950
2	6150	Babcock & Wilcox FH 26	233 MMBTUH	1950
3	6151	Babcock & Wilcox FH 26	233 MMBTUH	1950
4	6151	Babcock & Wilcox FH 26	233 MMBTUH	1955

EUG 9 Fuel-Burning Equipment

Various process heaters share stacks. The June 30, 2008 CD states that all fuel gas combustion devices (FGDs) are subject to NSPS Subpart J, effective June 30, 2008. HRMT has taken a voluntary limit equal to NSPS Subpart Ja; SO₂ emissions will be subject to the limit.

The following table shows available information for all heaters.

Source	Point ID	Manu- facturer	Burner Type	No. of Burners	MMBTUH (HHV)	Heater Date
Vacuum Tower Heater	6155	Foster-Wheeler	JZ-HEVD-16	14	100	1949
FCCU Charge B-2	6158	M W Kellogg	JZ-VBM-14	32	165	1949
FCCU Air Heater B-1 *	6159	M W Kellogg	Peabody M-18	1	38.4	1949
Unifiner Charge H-1	6167	Refinery Engr	JZ-UOV-4 Twin head	12	42	1955

* vents to FCCU regenerator stack.

EUG 10 Sulfur Recovery Units

SRU #1 was constructed in 1972 and SRU #2 became operational in June 2006. Each unit has a tail gas treating unit (TGTU) to scrub its exhaust. The TGTU #1 incinerator is rated at 5.6 MMBTUH and the TGTU #2 incinerator is rated at 12.1 MMBTUH. Scrubbed tail gas exhausts TGTU #1 at 3,640 ACFM and 443°F through a 2' diameter stack at 200' above grade. Scrubbed tail gas exhausts TGTU #2 at 7,400 ACFM at 154°F through a 2.5' diameter stack at 101' above grade. SRU/TGTU #1 is Point ID 6152, and SRU/TGTU #2 is Point ID 36200.

EUG 11 FCCU

Catalyst is regenerated in the FCCU regeneration section, where cyclones remove catalyst from the vent gas. Selective catalytic reduction (SCR) then controls NO_x before the exhaust stream reaches a wet gas scrubber (WGS), where SO₂ and further PM removal occurs. The only emission limits applied to this EUG are those imposed by the MACT Subpart UUU or the CD, as described in the Specific Conditions. Compliance with SO₂ and NO_x standards are demonstrated by continuous emission monitoring systems (CEMS) that monitor each pollutant and O₂. An alternative monitoring plan (AMP) was approved by EPA on January 31, 2013. A copy of the AMP is found in the Specific Conditions. Operation of the regenerator is regulated by MACT Subpart UUU. The ESP is identified as Point ID 6153. The CD established the regenerator as an affected facility under NSPS Subpart J. Compliance dates as stated in the CD and the modified CD depend on the pollutant and on the averaging period. These details are identified in the Specific Conditions. Approximately 60,000 acfm (wet) at roughly 150°F is exhausted through a 60" diameter stack at 151' above grade.

EUG 12 Flares

Each flare is steam assisted with three shielded pilots, flame front generators, and electronic igniters. Pilot flame presence is detected with either infrared cameras or thermocouples in the pilots. Throughputs are highly variable and exhaust temperatures are approximately 1,500°F. The current #1 flare tip was designed in 1968 for 65,000 lbs/hr of 42 average molecular weight gas. The #2 flare tip was designed for smokeless operation at 120,000 lbs/hr of 87 average molecular weight gas and 42,000 lbs/hr of steam, and has a maximum capacity of 352,600 lbs/hr of 67.8 average molecular weight gas. Both flare tips have a diameter of 5'. The June 30, 2008 CD required compliance with the H₂S standard of NSPS Subpart J by December 31, 2009. It also established the flares as affected facilities under NSPS Subpart J. Both flares will become subject the the standards of NSPS Ja on November 11, 2015. Sources in other EUGs under various regulations utilize the flares as air pollution control devices. As noted in the discussion of the FCCU (Section II B), flare #1 handles the CDU, FCCU, Alky, Poly, and Penex units, and flare #2 handles everything else. During normal refinery operations, both flares are joined to a common header and routed to the flare gas recovery unit. The flares are identified as Point ID 6154.

Flare	Make/Model	Height (ft)	Date
#1	Zink/STF-SA-18	230	1949
#2	Zink/STF-SA-36-C	250	1972

EUG 13 MACT EEEE Tanks

This EUG contains vessels subject to 40 CFR 63 Subpart EEEE. Because these perchloroethylene tanks are smaller than 5,000 gallons, these emission sources do not require control, per Subsection 63.2343(a).

Tank No.	Year Built	Height	Diameter	Nominal Capacity
10F-163 (CCR)	2007	4'	8'	18 bbl
4V-31 (Unifiner)	2002	13.5'	4.5'	30 bbl

EUG 15 High Vapor Pressure Loading Operations

There are several loading racks that handle VOC materials. The propylene and butane truck loading facilities are on vapor balance systems. The butane rack is “grandfathered” (constructed prior to any applicable rule). There are no emission limits applied to this EUG under Title V but it is limited to the existing equipment as it is.

Rack	Point ID	Material	Capacity	Date
Butane truck	6171	Butane loading and unloading	4 trucks	1923
Propylene	13404	Propylene loading	2 cars, 2 trucks	Railcars/1996, Trucks/1997

EUG 16 Fugitive Emissions

Equipment leak emissions from components throughout the existing refinery but not including the proposed new process units (Naphtha Fractionation, LPG and ROSE), or modified units (DHTU, NHDS, and ALKY) including but not limited to the process units and storage tanks are included in this Group. There are no emission limits applied to this EUG under Title V but it is limited to the existing equipment as it is. VOC concentrations in ppm are limited by various rules and regulations, including MACT Subpart CC and OAC 252:100-39-15. Aggregated emission points are identified as Point ID 6172.

EUG 17 Wastewater System

The wastewater system consists of several different sewer systems and the wastewater treatment plant, as described in Part N of Section II (Facility Description) above. The facility is subject to 40 CFR 61 Subpart FF (BWON) and 40 CFR 63 Subpart CC (MACT CC), while areas of the refinery are subject to 40 CFR 60 Subpart QQQ (NSPS QQQ). Due to the overlap regulations under MACT CC (40 CFR 63.640(o)), all Group 1 wastewater streams also regulated under NSPS QQQ must meet only MACT CC standards, while all Group 1 wastewater streams also regulated under BWON must meet only BWON standards. A June 11, 2007, EPA Applicability Determination (AD) issued to BP Products North America and signed by George Czerniak, states that a Group 2 wastewater stream may be treated under BWON exclusively if the facility declares it to be Group 1 and satisfies the requirements of Subpart FF for the stream. Given this AD, the entire SCAN Unit, entire NHDS Unit, and new construction at the DHTU and CCR are

subject to BWON. The entire SRU/TGTU #2 is subject to NSPS Subpart QQQ. Aggregated emission points are identified as Point ID 13409.

The proposed new ROSE Unit and Naphtha Fractionation Column will have new process drains constructed, drains which will be subject to NSPS Subpart QQQ and NESHAPS Subpart CC. By the overlap provisions of Subpart CC, the new wastewater equipment is required to comply only with Subpart CC.

EUG 18 Hydrocarbon Recovery System

This system was installed in 1982 to recover oil and any other hydrocarbons that may be below the surface of the ground within the refinery. Several wells and tank batteries are involved. Any water recovered is sent to the Wastewater Treatment System and all oil is processed in the refinery. This EUG has no emission limitation. New tanks were installed in 2007, 2008, and 2009. The collection of all points is identified as Point ID 14487.

Tank No.	Height (feet)	Diameter (feet)	Nominal Capacity
B1	6	3.8	12 bbl
B2	6	3.8	12 bbl
B4	6	3.8	12 bbl
B5	N/A	N/A	55 gallons
B7	6	3.8	12 bbl
B8	6	3.8	12 bbl
B9	6	3.8	12 bbl
B10	6	3.8	12 bbl
B11	6	3.8	12 bbl
B12	6	3.8	12 bbl

EUG 19 Cooling Towers

Number	Point ID	Purpose	Date
3	25053	Cooling water for the FCCU	1949
3a	25054	Cooling water for SCAN	2003
4 and 5	25055	Cooling water for the CDU	1949
7	25056	Cooling water for the ALKY, POLY & ISOM	2007*
8	25057	Cooling water for the OIF	1972
7a	25056a	Cooling water for the ALKY, POLY & ISOM	2012

* Replaced tower built in 1949.

EUG 20 NSPS Kb Tanks (EFR) - MACT CC Group 1 Wastewater

These storage vessels are regulated under 40 CFR 60, Subpart Kb and is limited to the existing equipment as it is. Due to the overlap provisions of MACT CC, these vessels are required to comply only with Subpart Kb, except as noted in 40 CFR 63.640(n)(8).

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
476	36590	2005	45'	55'	15,000
478	N/A*	2014	59'	102'	100,000
477	N/A	2006	40'	30'	5,000
474	15940	1997	48'	106'	73,000
475	15941	1997	48'	106'	73,000

*Tank 478 is being replaced and a new Point ID number has not yet been assigned.

EUG 21 Pressurized Spheres

These units are “grandfathered” (constructed prior to any applicable rule). There are no emission limits applied to this EUG under Title V but it is limited to the existing equipment as it is. Because there are no measurable emissions from any of these tanks, they are all classified as Insignificant, and listed here only for completeness.

Tank No.	Point ID	Year Built	Diameter (feet)	Nominal Capacity (bbls)
207	6281	1948	48	9,250
208	6282	1924	48	9,250
218	6284	1986	55	13,750
219	6285	1986	55	13,750
220	6286	1953	51	10,800
221	6287	1953	51	10,800

EUG 22 Pressurized Bullet Tanks

Because there are no measurable emissions from these tanks, they are all classified as Insignificant, and listed only for completeness.

Tank No.	Point ID	Year Built	Length (feet)	Diameter (feet)	Nominal Capacity (bbls)
58	6288	1960	66	12	1,300
59	6289	1960	66	12	1,300
60	6290	1960	66	12	1,300
64	6291	1967	84	10	1,300

Tank No.	Point ID	Year Built	Length (feet)	Diameter (feet)	Nominal Capacity (bbls)
65	6292	1967	84	10	1,300
66	6293	1967	84	10	1,300
70	6294	1979	70	11	1,000
71	6295	1979	70	11	1,000
72	6296	1998	78	10	1,000
73	6297	1998	78	10	1,000

EUG 23 MACT CC Group 2 Wastewater Tanks

These tanks were incorrectly identified in earlier permits. They are affected facilities under MACT CC, but there are no standards or requirements under Subpart CC. Therefore, the only requirements are those of NESHAP Subpart FF.

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
52	22638	1972	36'	40'	7,500
56	36193	1992	16'	25'	1,400
57	36193	1992	16'	25'	1,400
140	23134	1971	16'	36'	2,900
369	23134	1960	23'	12'	480

EUG 24 Tanks Subject to NESHAP FF

The following tank is subject to the benzene waste organic NESHAP, but is too small to be an affected facility under the Refinery MACT.

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
67	23134	1992	12'	10'	165

EUG 25 New Fuel-Burning Equipment with Heat Input < 100 MMBTUH

This EUG contains new fuel-burning equipment with heat input less than 100 MMBTUH. These sources are all regulated under NSPS J and MACT DDDDD.

Source	Point ID	Manufacturer	Burner Type	No. of Burners	MMBTUH (HHV)	Heater Date	NO _x lb/MMBTU (HHV)
SCAN Charge (12H-101)	23133	Tulsa Heaters, Inc	ZeeCo New Gen Low NO _x	3	25.2	2004	0.07
NHDS Charge (02H-001)	36195	Tulsa Heaters, Inc	ZeeCo Low NO _x	4	39	2006	0.05
NHDS Stripper Reboiler (02H-002)	36198	Tulsa Heaters, Inc	ZeeCo Next Gen Low NO _x	6	44.2	2006	0.05

EUG 26 New Fuel-Burning Equipment with Heat Input ≥ 100 MMBTUH

This source is currently regulated under NSPS Subpart Ja and to MACT Subpart DDDDD. The interheater has emissions of approximately 55,800 acfm and 380°F venting through an 8.3' diameter stack at 125' above grade. The capacity of this unit has historically been poorly documented. The rated capacity will be increased from 141.8 to 155 MMBTUH, and the fuel sulfur limits of NSPS Subpart Ja will be accepted. However, the increased rating will not be accompanied with a physical change.

Source	Point ID	Manufacturer	Burner Type	No. of Burners	MMBTUH (HHV)	Heater Date	NO _x lb/MMBTU (HHV)
CCR #1 Interheater (10H-113)	39225	Tulsa Heaters, Inc	ZeeCo, Inc.	18	155	2005	0.05

EUG 27 Existing Fuel-Burning Equipment with NO_x Limits

The June 30, 2008 CD states that all fuel gas combustion devices (FGDs) are subject to NSPS Subpart J, effective June 30, 2008.

Stack	Height (ft)	Diameter (Ft)	Temp (°F)	Flow (ACFM)
DHTU	140	4.8	590	24,750
CCR Reboiler	124	4.5	500	22,000
CCR Heaters	124	5.8	550	103,300
Naphtha Splitter Reboiler	124	4.5	500	65,800

The following list shows available information for heaters in this EUG.

Source	Point ID	Manu-facturer	Burner Type	No. of Burners	MMBTUH (HHV)	Heater Date	NO _x lb/MMBTU (HHV)
DHTU Reactor Charge 1H-101	6156	Foster-Wheeler	JZ-LOF-27-30	16	55	1972**	0.20
CCR Charge Heater 10H-101	6163	SELAS	JZ MA-20	12	120	1972*	0.05
CCR Inter-heater #2-1 10H-102	6163	SELAS	Callidus CRG-LN-8P	8	101	1972	0.20
CCR Interheater #2-2 10H-103	6163	SELAS	JZ MA-22	2	25	1972	0.20
CCR Stabilizer Reboiler 10H-104	6162	SELAS	JZ MA-20	8	85	1972*	0.05
Naphtha Splitter Reboiler	6162	Zeeco	GLSF Free Jet	--	75	1972	0.04

* low-NO_x burners installed in 2005.

**Low-NO_x burners installed in 2011.

EUG 34 Stationary Engines Subject to 40 CFR Part 63 Subpart ZZZZ

ID Number	HP	Description	Construction/Modification Date
007-J-26G	75	Kohler 50RZB 4SRB emergency engine	2004
008-PA-50	75	Kohler 50RZGB-051 4SRB emergency engine	2003
050-G-1M	66	Kohler 20RZ-Q5 4SRB emergency engine	2002
004-G-1	104	Kohler 304Z-QS 4SRB emergency engine	2001
012-G-1M	421	Kohler 275RZD 4SRB emergency engine	2004

EUG 34a Stationary Engines Subject to 40 CFR Part 60 Subpart JJJJ

ID Number	HP	Description	Construction/Modification Date
045-G-1M	360	Kohler 275 RZDB 4SRB emergency engine	2010
006-PE-80M	45	Kohler 25RZGB 4SRB emergency engine	2008

EUG 35 Stationary Engines Subject to 40 CFR Part 63 Subpart ZZZZ

ID Number	HP	Description	Construction/Modification Date
009-PE-143	700	Cummins VT-1710-F CI emergency engine	1977
009-PE-144	262	John Deere 6081HF001 CI emergency engine	Pre-2002

EUG 35a Stationary Engines Subject to 40 CFR Part 60 Subpart JJJJ

ID Number	HP	Description	Construction/ Modification Date
033-EG-5320	700	Caterpillar C18 214-0021 CI emergency engine	2010
009-PE-152	380	Cummins CFP15E-F10 CI emergency engine	2014

EUG-28: LPG Recovery Unit Fugitive VOC Leaks

EU	Point	Equipment	Estimated Number of Items	Installed Date
LPG	N/A	Fugitive VOC Leakage Components at LPG Recovery Unit	150 gas/vapor valves	2014 - 2015
			150 light liquid valves	
			5 heavy liquid valves	
			660 flanges	
			8 light liquid pumps	
			2 heavy liquid pumps	
			15 gas relief valves	

EUG 29 New Fuel-Burning Equipment with Heat Input < 100 MMBTUH

This EUG contains new fuel-burning equipment with heat input less than 100 MMBTUH. These sources are all regulated under NSPS Ja and MACT Subpart DDDDD.

Source	Point ID	Burner Type	MMBTUH (HHV)	Heater Date	NO _x lb/MMBTU (HHV)
CCR Helper Heater	N/A	ULNB	25	2015	0.03
NHDS Helper Heater	N/A	ULNB	10	2015	0.03
DHTU Helper Heater	N/A	ULNB	45	2015	0.03
ROSE Heater	N/A	ULNB	42	2015	0.03
Frac Reboiler	N/A	ULNB	25	2015	0.03

EUG 30: ROSE Unit Fugitive VOC Leaks

EU	Point	Equipment	Estimated Number of Items	Installed Date
ROSE	N/A	Fugitive VOC Leakage Components at ROSE Unit	200 gas/vapor valves	2014 - 2015
			300 light liquid valves	
			70 heavy liquid valves	
			1,204 flanges	
			10 light liquid pumps	
			5 heavy liquid pumps	
			2 compressor seals	
			15 gas relief valves	

EUG 32: New/Modified Unit Fugitive VOC Leaks

EU	Point	Equipment	Estimated Number of Items	Installed Date
DHTU	N/A	Fugitive VOC Leakage Components at DHTU Unit	20 gas/vapor valves	2014 - 2015
			45 light liquid valves	
			2 light liquid pumps	
			144 flanges	
			5 gas relief valves	
NHDS	N/A	Fugitive VOC Leakage Components at NHDS Unit	20 gas/vapor valves	2014 - 2015
			45 light liquid valves	
			2 light liquid pumps	
			144 flanges	
			5 gas relief valves	
Alky	N/A	Fugitive VOC Leakage Components at Alky Unit	20 gas/vapor valves	2014 - 2015
			45 light liquid valves	
			2 light liquid pumps	
			144 flanges	
			5 gas relief valves	
FCCU Regenerator	N/A	Fugitive VOC Leakage Components at FCCU Regenerator Unit	50 gas/vapor valves	2014 - 2015
			75 light liquid valves	
			3 light liquid pumps	
			268 flanges	
			6 gas relief valves	
Naphtha Fractionation	N/A	Fugitive VOC Leakage Components at Naphtha Fractionation Column Unit	125 gas/vapor valves	2014 - 2015
			125 light liquid valves	
			3 light liquid pumps	
			524 flanges	
			1 compressor seal	
			8 gas relief valves	

EUG Plant-wide Entire Facility

This EUG is established to cover all rules or regulations that apply to the facility as a whole.

V. EMISSIONS**A. New / Modified Units Emissions (East Refinery)**

Emissions from the new heaters are based on continuous operation at rated heat input; NSPS Subpart Ja limits for SO₂ (162 ppm in RFG, 3-hour basis and 60 ppm in RFG, 365-day rolling average, NO_x emissions of 0.03 lb/MMBTU and CO emissions of 0.04 lb/MMBTU from BACT requirements. All other factors are from Tables 1.4-1 and 2 of AP-42 (7/98). A heating value of 1020 BTU/SCF was used for refinery fuel gas.

ROSE Heater: EUG-29

Unit Capacity	Pollutant	Emission Factor, lb/MMBTU	Emissions	
			lb/hr	TPY
42 MMBTUH	NO _x	0.03	1.26	5.52
	CO	0.04	1.68	7.36
	VOC	0.0054	0.23	0.99
	SO ₂	0.026 hourly 0.0098 annual	1.11	1.80
	PM ₁₀ / PM _{2.5}	0.0075	0.31	1.37
	GHG	163.29	6,858	30,039

DHTU Helper Heater: EUG-29

Unit Capacity	Pollutant	Emission Factor, lb/MMBTU	Emissions	
			lb/hr	TPY
50 MMBTUH	NO _x	0.03	1.50	6.57
	CO	0.04	2.00	8.76
	VOC	0.0054	0.27	1.18
	SO ₂	0.026 hourly 0.0098 annual	1.32	2.14
	PM ₁₀ / PM _{2.5}	0.0075	0.37	1.63
	GHG	163.29	8,164	35,761

NHDS Helper Heater: EUG-29

Unit Capacity	Pollutant	Emission Factor, lb/MMBTU	Emissions	
			lb/hr	TPY
10 MMBTUH	NO _x	0.03	0.30	1.31
	CO	0.04	0.40	1.75
	VOC	0.0054	0.05	0.24
	SO ₂	0.026 hourly 0.0098 annual	0.26	0.43
	PM ₁₀ / PM _{2.5}	0.0075	0.07	0.33
	GHG	163.29	1,633	7,152

CCR Helper Heater: EUG-29

Unit Capacity	Pollutant	Emission Factor, lb/MMBTU	Emissions	
			lb/hr	TPY
25 MMBTUH	NO _x	0.03	0.75	3.29
	CO	0.04	1.00	4.38
	VOC	0.0054	0.13	0.59
	SO ₂	0.026 hourly 0.0098 annual	0.66	1.07
	PM ₁₀ / PM _{2.5}	0.0075	0.19	0.82
	GHG	163.29	4,082	17,880

CDU Atmospheric Tower Heater: EUG-33

Unit Capacity	Pollutant	Emission Factor, lb/MMBTU	Emissions	
			lb/hr	TPY
248 MMBTUH	NO _x	0.03	7.44	32.59
	CO	0.04	9.92	43.45
	VOC	0.0054	1.34	5.87
	SO ₂	0.026 hourly 0.0098 annual	6.45	10.65
	PM ₁₀ / PM _{2.5}	0.0075	1.86	8.15
	GHG	163.29	40,496	177,372

Fugitive VOC leakage calculations used estimated numbers of new components and emissions factors from EPA's "1995 Protocol for Equipment Leak Emission Estimates," Table 2-4. Control efficiencies are from TCEQ guidance.

LPG Unit: EUG-28

LPG Unit: EUG 20							
EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
LPG	VOC Leakage at LPG Recovery Unit	gas valves	150	0.059	98%	0.18	0.78
		lt liq valves	150	0.024	98%	0.07	0.32
		hvy liq valves	5	0.00051	0%	0.01	0.01
		flanges	660	0.00055	30%	0.25	1.11
		lt liq pumps	8	0.251	85%	0.30	1.32
		hvy liq pumps	2	0.046	0%	0.09	0.40
		gas relief valves	15	0.35	98%	0.11	0.46
TOTALS						1.01	4.40

ROSE Unit: EUG-30

ROSE Unit: EUG 50							
EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
ROSE	VOC Leakage ROSE Unit	gas valves	200	0.059	98%	0.24	1.03
		lt liq valves	300	0.024	98%	0.14	0.63
		hvy liq valves	70	0.00051	0%	0.04	0.16
		flanges	1,204	0.00055	30%	0.46	2.03
		lt liq pumps	10	0.251	85%	0.38	1.65
		hvy liq pumps	5	0.046	0%	0.23	1.01
		gas relief valves	15	0.35	98%	0.11	0.46
		compr. seal	2	1.400	85%	0.42	1.84
TOTALS						2.02	8.81

Naphtha Fractionator Column: EUG-32

Naphtha Fractionator, Column, ECG 52							
EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
NAPH THA	VOC Leakage New Naphtha Fractionator Column	gas valves	125	0.059	98%	0.15	0.65
		lt liq valves	125	0.024	98%	0.06	0.26
		Flanges	524	0.00055	30%	0.20	0.88
		lt liq pumps	3	0.251	85%	0.11	0.50
		gas relief valves	8	0.35	98%	0.06	0.25
		compr. Seal	1	1.400	85%	0.21	0.92
TOTALS						0.79	3.46

New Components in RFG System: EUG-16

New Components in RFG System: VOC's							
EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
	VOC Leakage New Components of RFG System	gas valves	365	0.059	98%	0.43	1.89
		flanges	824	0.00055	30%	0.32	1.39
		lt liq pumps	11	0.251	85%	0.41	1.81
		gas relief valves	36	0.35	98%	0.25	1.10
TOTALS						1.41	6.19

Modified CCR Unit: EUG-6

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
CCR	VOC Leakage CCR Unit	gas valves	20	0.059	98%	0.02	0.10
		lt liq valves	45	0.024	98%	0.02	0.10
		lt liq pumps	2	0.251	85%	0.08	0.33
		flanges	144	0.00055	30%	0.06	0.24
		gas relief valves	5	0.35	98%	0.04	0.15
TOTALS						0.22	0.92

Modified DHTU Unit: EUG-32

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
DHTU	VOC Leakage DHTU Unit	gas valves	20	0.059	98%	0.02	0.10
		lt liq valves	45	0.024	98%	0.02	0.10
		lt liq pumps	2	0.251	85%	0.08	0.33
		flanges	144	0.00055	30%	0.06	0.24
		gas relief valves	5	0.35	98%	0.04	0.15
TOTALS						0.28	1.23

Modified NHDS Unit: EUG-32

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
NHDS	VOC Leakage NHDS Unit	gas valves	20	0.059	98%	0.02	0.10
		lt liq valves	45	0.024	98%	0.02	0.10
		lt liq pumps	2	0.251	85%	0.08	0.33
		flanges	144	0.00055	30%	0.06	0.24
		gas relief valves	5	0.35	98%	0.04	0.15
TOTALS						0.28	1.23

Modified FCCU Regenerator Unit: EUG-32

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
FCCU Regen	VOC Leakage FCCU Regenerator Unit	gas valves	50	0.059	98%	0.06	0.26
		lt liq valves	75	0.024	98%	0.04	0.16
		lt liq pumps	3	0.251	85%	0.11	0.50
		flanges	268	0.00055	30%	0.10	0.45
		gas relief valves	6	0.35	98%	0.04	0.18
TOTALS						0.35	1.55

Modified Alky Unit: EUG-32

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
Alky	VOC Leakage Alky Unit	gas valves	20	0.059	98%	0.02	0.10
		lt liq valves	45	0.024	98%	0.02	0.10
		lt liq pumps	2	0.251	85%	0.08	0.33
		flanges	144	0.00055	30%	0.06	0.24
		gas relief valves	5	0.35	98%	0.04	0.15
TOTALS						0.28	1.23

New Process Drains (ROSE and Naphtha Fractionator): EUG-17

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
—	Process Drains at ROSE and Naphtha Fractionator	Process drains	2	0.035	--	0.07	0.31

Existing Units Emissions

Unless otherwise stated, all emission estimates in Section IV reflect operations as reported in the 2005 and 2006 Inventory Turn-Around Documents. Additionally, most VOC emissions are non-HAP only, unless otherwise indicated. HAP emissions were calculated EUG by EUG in the memorandum associated with the initial TV permit, and the reader may peruse that memorandum for more information concerning the methods used. HAP emissions reported for 2006 will be presented in aggregate near the end of this Section IV. Tanks shown as “Out of Service” or “Idle” had no activity in 2006. The “Contents” column of each table for tanks reflects information presented in the Turn-Around Document, and does not represent a classification or requirement. Assumptions and data used in calculating emissions for each EUG are reflected in the following analyses.

Fugitive VOC leakage calculations used estimated numbers of new components and emissions factors from EPA’s “1995 Protocol for Equipment Leak Emission Estimates,” Table 2-4. Control efficiencies are from TCEQ guidance.

EUG 4 MACT CC Wastewater Tanks

Non-HAP VOC emissions of 3.19 TPY are calculated using the current version of EPA’s TANKS program for slop oil Tank #13 with 13.2 turnovers in 2006. All other tanks in this EUG have negligible emissions.

EUG 6 Catalytic Reforming Unit (CCR)

Emission sources at the CCR are included in other EUGs.

EUG 8 Fired Boilers

Calculations assume all four units are operated continuously at rated capacity of 233 MMBTUH each. Natural gas emission factors are taken from AP-42 (3/98) Tables 1.4-1 and 2, assuming 1020 BTU/CF, except that SO₂ factors are taken assuming 60 ppmv H₂S in RFG 365-day rolling average basis and 162 ppmv 3-hour average basis at the boilers and NO_x factors are taken from requirements imposed in the CD. A 365-day rolling average of 0.03 lbs per MMBTU is required, so pound per hour limits are not set for NO_x.

Boiler Emissions

Pollutant	Lb/MMCF	Each Boiler		Four Boiler Total
		Lb/hr	TPY	TPY
NO _x	30.6	N/A	30.6	122
CO	84	19.2	84.0	336
PM ₁₀ /PM _{2.5}	7.6	1.74	7.60	30.4
SO ₂	26.5 hourly 10.0 annual	6.14	9.96	39.8
VOC	5.5	1.26	5.50	22.0

Emission factors for HAP were also reviewed, using AP-42 (3/98) Table 1.4-3. Only those factors resulting in 0.01 TPY or more of any constituent are reported here. The following table shows all of these constituents, picking the higher value when both fuels resulted in emissions of any single constituent. Emission totals from the 2006 Turn-around document are shown for comparison. Note that 2006 data for benzene included oil combustion, which has been discontinued.

Constituent	CAS #	Emissions (TPY)	
		Potential	2006
Formaldehyde	50-00-0	0.30	0.21
Hexane	110-54-3	7.20	0.74
Benzene	91-20-3	0.01	0.10
Toluene	108-88-3	0.01	0.25

EUG 9 Fuel-Burning Equipment

Various process heaters share stacks. Stack parameters follow the equipment list. Except for SO₂, natural gas emission factors are taken from AP-42 (3/98) Tables 1.4-1 and 2, assuming 1,020 BTU/CF. SO₂ factors are from sulfur content of the refinery fuel gas, assuming 60 ppmv H₂S 365-day rolling average basis and 162 ppmv 3-hour average basis. Note that actual heating values at certain units may vary widely from the standard mentioned. Because HRMT is unable to provide exact heat ratings for this equipment, the following emission estimates would not become more accurate through knowledge of the precise heating value of the fuel used by each heater. According to the CD, all heaters are affected facilities under NSPS Subpart J.

Source	Pollutant	Emission factor lb/MMCF	Emissions	
			lb/hr	TPY
CDU-vacuum	NO _x	100	9	39
	CO	84	7	32
	PM	7.6	0.7	2.9
	SO ₂	26.5 hourly 10.0 annual	2.6	4.3
	VOC	5.5	0.5	2.1
FCCU-charge (B-2)	NO _x	280	41	180
	CO	84	12	54
	PM	7.6	1.1	4.9
	SO ₂	26.5 hourly 10.0 annual	4.3	7.1
	VOC	5.5	0.8	3.5
FCCU-B-1	NO _x	100	4	17
	CO	84	3.2	14
	PM	7.6	0.3	1.3
	SO ₂	59	2	10
	VOC	5.5	0.2	0.9
ISOM-unifiner	NO _x	100	4	18
	CO	84	3.5	15
	PM	7.6	0.3	1.4
	SO ₂	26.5 hourly 10.0 annual	1.1	1.8
	VOC	5.5	0.2	1.0

The following table is a total of all preceding values.

Pollutant	lb/hr	TPY
NO _x	95	494
CO	43	187
PM	3.9	16
SO ₂	15	32
VOC	2.8	13

Emission factors for HAP were also reviewed, using AP-42 (3/98) Table 1.4-3. Only those factors resulting in 0.01 TPY or more of any constituent are reported here.

Constituent	CAS #	TPY
Formaldehyde	50-00-0	0.13
Hexane	110-54-3	3.26
Benzene	71-43-2	0.01
Toluene	108-88-3	0.01

EUG 10 Sulfur Recovery Units / Tail Gas Treating Units

Emission factors for the SRU #1 set are based on a Reference Method stack test for carbon monoxide, continuous emission monitoring (CEM) for SO_x, and natural gas combustion factors from Tables 1.4-1 and 2 of AP-42 (7/98) for NO_x, PM₁₀, and VOC. Emission factors for the SRU #2 set are all taken from the same AP-42 tables, except for SO_x, which is taken from CEMs. Emissions of all pollutants were authorized in two construction permits; No. 98-021-C (M-15), which covered construction of the SCAN Unit, and No. 98-021-C (M-26), which covered the Low Sulfur Diesel Project. Emissions authorized by those permits were established based on the following considerations.

- A voluntary limit was taken on SRU #1 for SO_x to avoid PSD consequences in the SCAN project.
- A limit based on the NSPS Subpart J standard of 250 ppm of SO_x was applied to the maximum possible exhaust from the unit.
- NO_x limits for each unit were set based on the maximum 0.20 lbs/MMBTU limit of OAC 252:100-33-2(a) for new gas-fired fuel-burning equipment.
- Limits for CO, PM₁₀, and VOC were all based on the AP-42 tables mentioned earlier. Subsequent reference method testing of CO emissions from SRU #1 required that a new limit be authorized by Permit No. 98-021-TV (M-52).

The following table lists the limits currently in place, along with the emissions recorded in the 2006 Turn-around document. Note that the only limits at SRU #1 are an annual limit on SO₂, taken to avoid PSD in Permit No. 98-021-C (M-16) and the CO limit associated with Permit No. 98-021-TV (M-52). VOC numbers include volatile HAP.

SRU #1 Emissions				SRU #2 Emissions		
Pollutant	Permit		2006	Permit		2006
	lb/hr	TPY	TPY	lb/hr	TPY	TPY
SO ₂		34.9	0.13	5.62	24.6	0.38
NO _x			1.15	1.12	4.91	2.32
PM ₁₀			0.09	0.04	0.18	0.18
VOC			0.02	0.03	0.13	0.05
CO		99	48.4	0.46	2.02	1.95

EUG 11 FCCU

Emission factors for NO_x and SO₂ are found in Table 5.1-1 of AP-42 (1/95). The particulate emission values are based on material balance and consider purchase and disposal of catalyst. PM means particulate greater than 2.5 microns. The FCCU is subject to a limitation of PM of 1.0 kg emissions per 1,000 kg coke burn-off. The VOC estimate is taken from EPA documents. Using 2006 FCCU feed of 6,689,000 barrels yields the following emission estimates. All of these estimates represent the FCCU before addition of the WGS and SCR. Actual emissions are expected to be lower than the numbers shown here. Emission standards stated in ppmv do not lend themselves to easy calculation of results, but testing subsequent to installation will provide a better basis for estimating future emissions.

Pollutant	Emission factor	Emissions (TPY)
PM	Mass balance	69.2
PM _{2.5}	Mass balance	92.3
NO _x	71 Lb/1000 barrels	237
CO	CEMs	44.3
SO ₂	493 Lb/1000 barrels	1,649
VOC	EPA	1.79

EUG 12 Flares

Emission factors are found in Table 5.1-1 of AP-42 (1/95). Using 2008 refinery feed of 22,060,000 barrels yields the following results. The facility is required to utilize a Flare Gas Recovery Unit (FGRU) to comply with the flaring limits of NSPS Subpart Ja, so future emissions will be somewhat less than the historic values shown.

Pollutant	Emission factor (lb/1,000 barrels)	Emissions (TPY)
PM ₁₀	Negligible	-0-
NO _x	18.9	297
CO	4.3	47.4
SO ₂	26.9	208
VOC	0.8	8.82
H ₂ S	Eng. estimate	0.01

EUG 13 MACT EEEE Tanks

These small tanks have negligible emissions and would be considered to be insignificant activities, were they not affected facilities under MACT EEEE.

EUG 15 High Vapor Pressure Loading Operations

There are several loading racks that handle VOC materials. Emissions from the butane and propylene racks are routed to the refinery flare.

Emissions from the propylene rack are calculated in a series of steps that depend on the loading process itself. The truck is a pressure vessel and the factors of Section 5.2 of AP-42 do not apply. The only loss consideration is the possible contents of the flexible lines used in the loading process and the physical state (phase, pressure, etc.) of the contents of these lines. Thus, a fixed amount of loss may be assigned to each loading event. Total product can be divided by the capacity of each truck to calculate the number of loading events. Loss per event multiplied by the number of events yields total emissions. The maximum loading rate of 15,000 gallons per hour can be used to calculate a maximum hourly emission rate of 6.16 lbs/hr of VOC. The maximum sustained production rate of 800 barrels per day yields an annual potential of 6.90 TPY. Actual loading of 5.44 MM gallons for 2008 resulted in VOC emissions of 0.75 TPY.

A similar approach was taken in analyzing butane rack emissions except that no maximum rate is available. Actual loading of 38.7 MM gallons for 2008 resulted in 3.5 TPY of VOC emissions.

Propane rack loading losses are negligible.

EUG 16 Fugitive Emissions

Equipment leaks from the process units are included in this Group. Piping and equipment associated with the cooling towers and with the wastewater system are included with the process units. Over 20,000 items were tabulated in the initial TV permit. There is at least one construction permit open and several modifications to the operating permit, all of which have the potential to slightly alter the total. The equipment count was detailed to process units and further refined to show type of service, such as gas, light liquid, etc., and finally divided as to components larger or smaller than two inches. Speciation of the VOC was based on testing or analysis of streams at each of the listed units. Total VOC was estimated at 838 TPY, HAP included, with the most highly-represented HAPs being hexane at 18.9 TPY, toluene at 18.0 TPY, and MTBE at 12.3 TPY.

EUG 17 Wastewater System

Emissions are calculated using EPA's WATER9 program for estimating air emissions from wastewater systems, "Air Emission Models Wastewater Treatment." The model was run using an outflow of 457,874,200 gallons (871 gpm) and measured concentrations of various constituents. Results are included in the EUG 16 totals.

EUG 18 Hydrocarbon Recovery System

Non-HAP VOC emissions too small to estimate were calculated using mass balance for the group of tanks involved, with total throughput of 2,500 gallons in 2008.

EUG 19 Cooling Towers

For the existing cooling towers, assuming drift to be 1.7 lbs/1,000 gals in these induced draft systems yields PM emissions of 62.2 TPY. This calculation of VOC PTE is based on factors found in Table 5.1-2 of AP-42 (1/95), using an aggregate circulation rate of 113,000 gpm. The 2008 emission inventory report showed entrained non-HAP VOC emissions of 19.4 TPY.

For the new tower (7a), PM emissions were calculated with a flow of 20,000 GPM, a drift of 0.0015%, and a dissolved solids content of 2,430 ppm. VOC emissions were calculated using a factor of AP-42 (1/95), Section 5.1 at 3.68 TPY.

EUG 20 NSPS Kb Tanks (EFR) - MACT CC Group 1 Wastewater

Tank 476 was estimated to have emissions of 1.90 TPY of VOC, with a throughput limit of 683 MMgpy. Turnaround document emissions for 2006 follow. Data for Tank 478 were taken from Permit Application No. 2012-1062-TVR (M-2).

Tank No.	Throughput, 1,000 gallons	VOC Emissions (TPY)
476	436,175	1.18
478	547,500	0.04

EUG 21 Pressurized Spheres

There are no emissions from these pressurized tanks. Fugitive emissions from associated piping are included in the calculations for EUG 16 above.

EUG 22 Pressurized Bullet Tanks

There are no emissions from these pressurized tanks. Fugitive emissions from associated piping are included in the calculations for EUG 16 above.

EUG 23 MACT CC Group 2 Wastewater Tanks

There are negligible emissions from the tanks in this EUG.

EUG 24 Tanks Subject to NESHAP FF.

There are negligible emissions from the tank in this EUG.

EUGs 25, 26, and 27 Fuel-Burning Equipment

Emissions of particulate (PM₁₀), carbon monoxide (CO), and VOC from all new and existing equipment are calculated based on factors found in Tables 1.4-1 and 2 of AP-42 (7/98). Oxides of nitrogen (NO_x) for new units and for those units modified with low-NO_x burners is estimated based on vendor performance data. The NO_x factor for existing units not modified for such burners is taken to be the OAC 252:100-33-2(a) limit of 0.20 lbs/MMBTU for new equipment. This factor differs from the AP-42 factor used in annual emission inventories. The SO₂ factor assumes a maximum concentration of 60 ppmv H₂S in RFG on a 365-day rolling average basis, and 162 ppmv H₂S on a 3-hour average basis, which is the Subpart Ja standard, and stoichiometric conversion to SO₂. All refinery fuel gas (RFG) is assumed to have a heating value of 1,020 BTU/CF.

EUG 25

Unit and heat rate	Pollutant	Emission factor	Emissions	
			Lbs/hr	TPY
NHDS Charge heater 39 MMBTUH	SO ₂	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	1.03	4.50
	NO _x	0.05 lb/MMBTU	4.95	8.54
	PM ₁₀	7.6 lb/MMCF	0.29	1.27
	VOC	5.5 lb/MMCF	0.21	0.92
	CO	84 lb/MMCF	3.21	14.1
NHDS Stripper reboiler 44.2 MMBTUH	SO ₂	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	1.17	5.10
	NO _x	0.05 lb/MMBTU	2.21	9.68
	PM ₁₀	7.6 lb/MMCF	0.33	1.44
	VOC	5.5 lb/MMCF	0.24	1.04
	CO	84 lb/MMCF	3.64	15.9
SCAN charge heater 25.2 MMBTUH	SO ₂	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	0.66	2.91
	NO _x	0.07 lb/MMBTU	1.76	7.73
	PM ₁₀	7.6 lb/MMCF	0.19	0.82
	VOC	5.5 lb/MMCF	0.14	0.60
	CO	84 lb/MMCF	2.08	9.09

EUG 26

Unit and heat rate	Pollutant	Emission factor	Emissions	
			Lbs/hr	TPY
CCR Interheater #1 155 MMBTUH	SO ₂	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	4.09	17.9
	NO _x	0.05 lb/MMBTU	7.75	33.9
	PM ₁₀	7.6 lb/MMCF	1.16	5.08
	VOC	5.5 lb/MMCF	0.85	3.73
	CO	84 lb/MMCF	13.0	57.0

EUG 27

Unit and heat rate	Pollutant	Emission factor	Emissions	
			Lbs/hr	TPY
CCR Charge heater 120 MMBTUH	SO ₂	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	3.16	13.9
	NO _x	0.05 lb/MMBTU	6.00	26.3
	PM ₁₀	7.6 lb/MMCF	0.89	3.92
	VOC	5.5 lb/MMCF	0.65	2.83
	CO	84 lb/MMCF	9.88	43.3
CCR Interheater #2 101 MMBTUH	SO ₂	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	2.66	11.7
	NO _x	0.20 lb/MMBTU	20.2	88.5
	PM ₁₀	7.6 lb/MMCF	0.75	3.30
	VOC	5.5 lb/MMCF	0.54	2.39
	CO	84 lb/MMCF	8.32	36.4
CCR Interheater #2 25 MMBTUH	SO ₂	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	0.66	2.89
	NO _x	0.20 lb/MMBTU	5.00	21.9
	PM ₁₀	7.6 lb/MMCF	0.19	0.82
	VOC	5.5 lb/MMCF	0.13	0.59
	CO	84 lb/MMCF	2.06	9.02
CCR Stabilizer reboiler 85 MMBTUH	SO ₂	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	2.24	9.82
	NO _x	0.05 lb/MMBTU	4.25	18.6
	PM ₁₀	7.6 lb/MMCF	0.63	2.77
	VOC	5.5 lb/MMCF	0.46	2.01
	CO	84 lb/MMCF	7.00	30.7
DHTU Charge heater 55 MMBTUH	SO ₂	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	1.45	6.35
	NO _x	0.20 lb/MMBTU	11.0	48.2
	PM ₁₀	7.6 lb/MMCF	0.41	1.79
	VOC	5.5 lb/MMCF	0.30	1.30
	CO	84 lb/MMCF	4.53	19.8
Naphtha Splitter Reboiler 75 MMBTUH	SO ₂	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	1.98	8.66
	NO _x	40 lb/MMCF	3.0	13.1
	PM ₁₀	7.6 lb/MMCF	0.6	2.5
	VOC	5.5 lb/MMCF	0.4	1.8

EUGs 34, 34a, 35, and 35a Emergency Stationary Internal Combustion Engines

Engine emissions are based on 500 hours per year operations

EUG 34

Unit and HP	Pollutant	Emission factor	Emissions	
			lbs/hr	TPY
007-J-26G (75 HP; 0.6 MMBTU)	NO _x	4.08 lb/MMBTU	2.45	0.61
	CO	0.557 lb/MMBTU	0.33	0.08
	VOC	0.118 lb/MMBTU	0.07	0.02
	PM ₁₀ /PM _{2.5}	0.01 lb/MMBTU	0.01	0.01
	SO ₂	0.0006 lb/MMBTU	0.01	0.01
008-PA-50 (75 HP; 0.6 MMBTU)	NO _x	4.08 lb/MMBTU	2.45	0.61
	CO	0.557 lb/MMBTU	0.33	0.08
	VOC	0.118 lb/MMBTU	0.07	0.02
	PM ₁₀	0.01 lb/MMBTU	0.01	0.01
	SO ₂	0.0006 lb/MMBTU	0.01	0.01
050-G-1M (66 HP; 0.53 MMBTU)	NO _x	4.08 lb/MMBTU	2.15	0.54
	CO	0.557 lb/MMBTU	0.29	0.07
	VOC	0.118 lb/MMBTU	0.06	0.02
	PM ₁₀	0.01 lb/MMBTU	0.01	0.01
	SO ₂	0.0006 lb/MMBTU	0.01	0.01
004-G-1 (104 HP; 0.83 MMBTU)	NO _x	4.08 lb/MMBTU	3.39	0.85
	CO	0.557 lb/MMBTU	0.46	0.12
	VOC	0.118 lb/MMBTU	0.10	0.02
	PM ₁₀	0.01 lb/MMBTU	0.01	0.01
	SO ₂	0.0006 lb/MMBTU	0.01	0.01
012-G-1M1 (421 HP; 3.37 MMBTU)	NO _x	4.08 lb/MMBTU	13.70	3.44
	CO	0.557 lb/MMBTU	1.88	0.47
	VOC	0.118 lb/MMBTU	0.40	0.10
	PM ₁₀	0.01 lb/MMBTU	0.03	0.01
	SO ₂	0.0006 lb/MMBTU	0.01	0.01

EUG 34a

Unit and heat rate	Pollutant	Emission factor	Emissions	
			lbs/hr	TPY
045-G-1M (360 HP; 2.88 MMBTU)	NO _x	2.21 lb/MMBTU	6.36	1.59
	CO	3.51 lb/MMBTU	10.11	2.53
	VOC	0.030 lb/MMBTU	0.09	0.02
	PM ₁₀	0.01 lb/MMBTU	0.03	0.01
	SO ₂	0.0006 lb/MMBTU	0.01	0.01
006-PE-80M (45 HP; 0.36 MMBTU)	NO _x	4.08 lb/MMBTU	1.47	0.37
	CO	0.557 lb/MMBTU	0.20	0.05
	VOC	0.118 lb/MMBTU	0.04	0.01
	PM ₁₀	0.01 lb/MMBTU	0.01	0.01
	SO ₂	0.0006 lb/MMBTU	0.01	0.01

EUG 35

Unit and heat rate	Pollutant	Emission factor	Emissions	
			lbs/hr	TPY
009-PE-143 (700 HP; 5.6 MMBTU)	NO _x	0.024 lb/hp-hr	16.80	4.20
	CO	0.055 lb/hp-hr	3.85	0.96
	VOC	0.0007 lb/hp-hr	0.49	0.12
	PM ₁₀	0.0007 lb/hp-hr	0.49	0.12
	SO ₂	0.0004 lb/hp-hr	0.28	0.07
009-PE-144 (216 HP; 1.73 MMBTU)	NO _x	0.031 lb/hp-hr	6.70	1.67
	CO	0.0067 lb/hp-hr	1.44	0.36
	VOC	0.0025 lb/hp-hr	0.53	0.13
	PM ₁₀	0.0022 lb/hp-hr	0.48	0.12
	SO ₂	0.00205 lb/hp-hr	0.44	0.11

EUG 35a

Unit and heat rate	Pollutant	Emission factor	Emissions	
			lbs/hr	TPY
033-EG-5320 (700 HP; 5.6 MMBTU)	NO _x	0.024 lb/hp-hr	16.80	4.20
	CO	0.055 lb/hp-hr	3.85	0.96
	VOC	0.0007 lb/hp-hr	0.49	0.12
	PM ₁₀	0.0007 lb/hp-hr	0.49	0.12
	SO ₂	0.0004 lb/hp-hr	0.28	0.07
009-PE-152 (380 HP; 3.04 MMBTU)	NO _x	2.78 g/hp-hr	2.33	0.58
	CO	0.7 g/hp-hr	0.56	0.14
	VOC	0.10 g/hp-hr	0.08	0.02
	PM ₁₀	0.09 g/hp-hr	0.08	0.02
	SO ₂	0.0004 lb/hp-hr	0.15	0.04

Total Engine Emissions

Pollutant	Lb/hr	TPY
NO _x	74.60	18.66
CO	23.30	5.82
VOC	2.42	0.60
PM ₁₀	1.65	0.45
SO ₂	1.22	0.36

Facility-wide Emission Totals

The following table summarized all of the estimated individual EUG emission amounts as they existed in the original renewal. Note that only those numbers arising from equipment with clearly stated capacities or ratings can be assumed to represent maximum emissions. All other data represented the refinery as it operated in 2006. There is very little information available as to “design” capacity of any Unit, because refining is an evolutionary process, with more efficient use of existing equipment allowing greater throughput. Review the design capacity discussion in Section II for further details.

TOTAL FACILITY CRITERIA POLLUTANTS

Pollutant	TOTALS TPY
NO _x	2,454
CO	951
SO ₂	3,080
PM	318
Non-HAP VOC	627

The following table of HAP emissions is taken from the 2006 Turnaround document and is not an attempt to analyze potential-to-emit for any pollutant.

HAPs

Pollutant	CAS #	TPY
1,1,1-Trichloroethane	71-55-6	<.01
1,3-Butadiene	106-99-0	0.30
2,2,4-Trimethylpentane	540-84-1	8.73
Acetaldehyde	75-07-0	0.12
Acrolein	107-02-8	0.08
Antimony & compounds	NA	0.02
Arsenic compounds	NA	0.01
Benzene	71-43-2	8.19
Biphenyl	92-52-4	0.76
Cadmium & compounds	NA	0.01
Carbon disulfide	75-15-0	0.65
Carbonyl sulfide	463-58-1	2.21
Chromium & compounds	NA	0.05
Cobalt & compounds	NA	0.02

Pollutant	CAS #	TPY
Cresols	1319-77-3	0.03
Cumene	98-82-8	1.00
Cyanide & compounds	NA	3.00
Diethanolamine	111-42-2	0
Ethylbenzene	100-41-4	4.57
Formaldehyde	50-00-0	1.97
n-Hexane	110-54-3	36.48
Lead & compounds	NA	0.03
Manganese compounds	NA	0.05
Mercury & compounds	NA	<.01
Methanol	67-56-1	<.01
Naphthalene	91-20-3	11.16
Nickel & compounds	NA	0.45
Phenol	108-95-2	0.07
Selenium & compounds	NA	0.04
Styrene	100-42-5	0.01
Toluene	108-88-3	24.20
Vinylidene chloride	75-35-4	0
Xylene	1330-20-7	23.84

NET EMISSIONS CHANGES

The initial step in the process of determining net emissions changes was summing the post-project potential emissions for each new unit, each modified unit, and each unit with increased utilization. These totals exceeded the PSD levels of significance for NO_x, CO, VOC, SO₂, PM_{2.5}/PM₁₀, and GHG, requiring determination of net emissions changes.

Net emissions changes for the project were calculated by using the post-project potential emissions for each new unit, each modified unit, and each unit with increased utilization compared to the Baseline Actual Emissions (BAE) for each. The Projected Actual Emissions (PAE) for each new, modified, and increased-utilization unit were taken as PTE, except for SO₂. To remain under the 40 TPY SER for SO₂, the PAE for the SRUs will be based on 100 ppmv SO₂ and the PAE for the FCCU regenerator will be based upon 10 ppmv SO₂. (Reported actual SO₂ emissions have been well below these projected values.)

The BAE period for all pollutants was calendar years 2010 and 2011.

There were several contemporaneous projects:

- Numerous pipelines were constructed between the two refineries as part of the “integration” project.
- The DHTU was revamped to meet new diesel fuel sulfur standards.
- The CCR was upgraded to a higher throughput.
- Boilers 3 and 4 at the West Refinery have been shut down.
- Boiler 10 at the West Refinery was installed under a PSD permit; as a unit operating less than 2 years, BAE is equal to PAE, for a net change of zero in this latest expansion.
- Sulfur reduction projects: flare gas recovery at the West Refinery, NaSH/Amine Unit at the East Refinery, and sour gas fuel line interconnection; the BAE for fuel gas combustion units at the West Refinery uses NSPS Subpart J limits as required by Consent Decree.
- Coker blowdown project at West Refinery.
- “Benzap” (Mobile Source Air Toxics) Unit, which has been repurposed as the Naphtha Splitter Reboiler.
- Loading Terminal vapor combustion unit.
- The East and West Refinery wastewater treatment plants have been upgraded or will be upgraded contemporaneous with the Project, resulting in VOC emissions reductions.
- Numerous older, grandfathered tanks have been replaced with newer tanks, mostly with floating roofs; despite the throughput increase, VOC emissions from tanks will decline from the BAE.

Baseline Actual Emissions

Unit	Point ID	NO _x TPY	CO TPY	VOC TPY	PM ₁₀ TPY	PM _{2.5} TPY	SO ₂ TPY	GHG TPY
East Refinery								
DHTU Charge Heater 1H-101	6156	3.29	12.9	0.84	1.16	1.16	0.20	20,414
CCR Charge Heater 10H-101	6163	24.5	19.7	1.29	1.78	1.78	0.30	31,251
CCR #2-1 Interheater 10H-102	6163	12.8	10.4	0.68	0.94	0.94	0.16	16,428
CCR #2-1 Interheater 10H-103	6163	6.31	5.11	0.33	0.46	0.46	0.08	8,103
CCR Stabilizer Reboiler 10H-104	6162	3.30	0.09	0.51	0.70	0.70	0.12	12,236
Naphtha Splitter Reboiler	6162	0.32	0.67	0.044	0.06	0.06	0.027	1,059
CCR Interheater #1 10H-113	39225	14.7	31.0	2.03	2.80	2.80	0.48	49,103
Boiler #1	6150	3.61	39.1	2.56	3.53	3.53	0.59	62,043
Boiler #2	6150	5.10	42.1	2.75	3.80	3.80	0.62	66,720
Boiler #3	6151	2.34	40.5	2.65	3.66	3.66	0.62	64,305
Boiler #4	6151	4.88	37.4	2.45	3.38	3.38	0.55	59,303
Sulfur Recovery Unit / Tail Gas Treating Unit #1	6152	0.36	37.2	0.014	0.02	0.02	0.90	345
Sulfur Recovery Unit / Tail Gas Treating Unit #2	36200	3.00	1.80	0.12	0.16	0.16	0.19	2,852
NHDS Charge Heater 02H-001	36195	3.46	0.04	0.42	0.58	0.58	0.10	10,259
NHDS Stripper Reboiler 02H-002	36198	2.84	0.38	0.37	0.52	0.52	0.09	9,063
CDU Atmospheric Tower Heater	6155	84.4	57.9	3.79	5.24	5.24	1.30	91,888
CDU Vacuum Tower Heater	6155	41.6	28.5	1.87	2.58	2.58	0.64	45,258
FCCU Charge Heater B-2	6158	33.3	18.3	1.20	1.65	1.65	0.31	20,414
FCCU Regenerator	6153	3.08	75.1	0.094	30.2	30.2	9.17	158,360
Unifiner Charge Heater H-1	6167	7.31	6.02	0.39	0.54	0.54	0.091	9,554
Scanfiner Charge Heater 12H-101	23133	1.20	0.01	0.092	0.13	0.13	0.023	2,234
Tanks	Multiple	-	-	3.19	-	-	-	62
Equipment Leaks		-	-	204	0.27	0.027	0	267
Wastewater Treatment	---	-	-	240	-	-	-	-
HEP (Loading Terminal)								-
Tanks	Multiple	-	-	156	-	-	-	62
Loading/Unloading Racks (excluding Terminal)	---	-	-	3.62	-	-	-	-
Loading Terminal	6275	14.84	37.10	37.5	1.48	1.48	0.39	9,214
Fugitives	N/A	-	-	2.56	0.27	0.027	-	267

Baseline Actual Emissions - Continued

Unit	Point ID	NO _x TPY	CO TPY	VOC TPY	PM ₁₀ TPY	PM _{2.5} TPY	SO ₂ TPY	GHG TPY
West Refinery								
#7 Boiler	#7 Boiler	46.9	20.3	1.33	1.84	1.84	0	32,261
#8 Boiler	#8 Boiler	69.0	29.9	1.96	2.71	2.71	0	47,469
#9 Boiler	#9 Boiler	53.4	31.4	2.06	2.84	2.84	0	49,843
#10 Boiler	#10 Boiler	39.0	77.4	5.07	7.00	7.00	9.17	122,776
CDU Atmospheric Tower Heater	CDU H-1	112	85.1	5.57	7.70	7.70	30.9	135,020
CDU #1 Vacuum Tower Heater	CDU H-2	30.6	25.2	1.65	2.28	2.28	46.7	39,951
CDU #2 Vacuum Tower Heater	CDU H-3	8.97	7.39	0.48	0.67	0.67	2.7	11,723
Unifiner Charge Heater	Unifiner H-2	9.03	4.96	0.32	0.45	0.45	1.69	7,867
Unifiner Stripper Reboiler	Unifiner H-3	13.2	7.24	0.47	0.66	0.66	2.46	11,491
No. 2 Platformer Charge Heater	#2 Plat PH-3	8.20	4.50	0.29	0.41	0.41	1.53	7,138
No. 2 Platformer Charge Heater	#2 Plat PH-4	9.93	5.45	0.36	0.49	0.49	0.68	8,649
Coker Drum Charge Heater	Coker B-1	11.6	10.6	0.70	0.96	0.96	0.01	16,887
Coker Pre-Heater	Coker H-3	5.31	4.86	0.32	0.44	0.44	0.004	7,708
LEU Raffinate Mix Heater	LEU H101	7.31	4.01	0.26	0.36	0.36	1.68	6,363
LEU Extract Mix Heater	LEU H-102	32.6	29.8	1.95	2.70	2.70	167	47,303
LEU Hydrotreater Charge Heater	LEU H-201	9.16	5.03	0.33	0.45	0.45	2.10	7,977
MEK – Wax Free Oil Heater	MEK H-101	36.3	19.9	1.30	1.80	1.80	0	31,595
MEK – Soft Wax Heater	MEK H-2	13.1	9.00	0.59	0.81	0.81	3.40	14,282
Loading / Unloading Racks	Multiple	-	-	6.40	-	-	-	-
Tanks	Multiple	-	-	78.3	-	-	-	73
Fugitive VOC Leakage	---	-	-	168	1.68	0.11	-	198
Wastewater Treatment	---	-	-	196	-	-	-	-
TOTAL BASELINE ACTUAL EMISSIONS		792.15	883.36	1145.1	102.16	100.10	286.78	1,357,638

Post-Project Potential To Emit For NO_x, CO, VOC, PM₁₀, PM_{2.5}, and GHG / SO₂ Projected Actual Emissions

Unit	Point ID	NO _x TPY	CO TPY	VOC TPY	PM ₁₀ TPY	PM _{2.5} TPY	SO ₂ TPY	GHG TPY
East Refinery								
CCR Helper Heater	N/A	3.29	4.38	0.59	0.82	0.82	1.07	17,880
NHDS Helper Heater	N/A	1.31	1.75	0.24	0.33	0.33	0.43	7,152
DHTU Helper Heater	N/A	6.57	8.76	1.18	1.63	1.63	2.14	35,761
ROSE Heater	N/A	5.52	7.36	0.99	1.37	1.37	1.80	30,039
New Tanks	Multiple	-	-	1.20	-	-	-	29.0
Fugitives – New/modified Units	Multiple	-	-	23.5	-	-	-	347.5
DHTU Charge Heater 1H-101	6156	9.64	19.8	1.30	1.79	1.79	0.98	39,337
CCR Charge Heater 10H-101	6163	26.3	43.3	2.83	3.92	3.92	2.14	85,825
CCR #2-1 Interheater 10H-102	6163	66.4	36.4	2.39	3.30	3.30	1.8	72,236
CCR #2-1 Interheater 10H-103	6163	16.4	9.02	0.59	0.82	0.82	0.45	17,880
CCR Stabilizer Reboiler 10H-104	6162	18.6	30.7	2.01	2.77	2.77	1.51	60,793
Naphtha Splitter Reboiler	6162	13.1	27.9	1.77	2.45	2.45	1.34	53,641
CCR Interheater #1 10H-113	39225	33.9	55.9	3.66	5.06	5.06	2.76	110,858
Boiler #1	6150	30.6	84.0	5.50	7.60	7.60	4.15	166,644
Boiler #2	6150	30.6	84.0	5.50	7.60	7.60	4.15	166,644
Boiler #3	6151	30.6	84.0	5.50	7.60	7.60	4.15	166,644
Boiler #4	6151	30.6	84.0	5.50	7.60	7.60	4.15	166,644
Sulfur Recovery Unit / Tail Gas Treating Unit #1	6152	4.91	99.0	0.13	0.18	0.18	14.0	3,604
Sulfur Recovery Unit / Tail Gas Treating Unit #2	36200	10.6	4.36	0.29	0.39	0.39	9.84	7,787
NHDS Charge Heater 02H-001	36195	8.54	14.1	0.92	1.27	1.27	0.69	27,893
NHDS Stripper Reboiler 02H-002	36198	9.68	15.9	1.04	1.44	1.44	0.79	31,612
CDU Atmospheric Tower Heater *	6155	84.4	57.9	5.86	8.09	8.09	4.42	143,042
CDU Vacuum Tower Heater	6155	52.6	36.1	2.36	3.26	3.26	1.78	71,521
FCCU Charge Heater B-2	6158	108	59.5	3.90	5.38	5.38	2.94	118,010
FCCU Regenerator	6153	33.2	505	0.094	74.5	74.5	23.1	293,591
Unifiner Charge Heater H-1	6167	18.4	15.1	0.99	1.37	1.37	0.75	30,039
Scanfiner Charge Heater 12H-101	23133	7.73	9.09	0.60	0.82	0.82	0.45	18,023
Tanks	Multiple	-	-	3.19	-	-	-	80.5
Equipment Leaks	Multiple	-	-	211	0.27	0.027	-	334
Wastewater Treatment	---	-	-	240	-	-	-	-

Post-Project Potential To Emit For NO_x, CO, VOC, PM₁₀, PM_{2.5}, and GHG / SO₂ Projected Actual Emissions - Continued

Unit	Point ID	NO _x TPY	CO TPY	VOC TPY	PM ₁₀ TPY	PM _{2.5} TPY	SO ₂ TPY	GHG TPY
West Refinery								
PDA/ROSE Heater	N/A	10.0	13.3	1.79	2.48	2.48	3.25	54,356
Hydrogen Plant Reformer Heater	---	16.4	21.9	2.95	4.08	4.08	5.34	89,401
Hydrogen Plant Process Emissions	---	-	4.06	-	-	-	-	75,991
New Tanks	---	-	-	25.8	-	-	-	29.0
New Fugitives	---	-	-	5.22	-	-	-	258
#7 Boiler	#7 Boiler	125	54.1	3.54	4.90	4.90	2.67	107,282
#8 Boiler	#8 Boiler	125	54.1	3.54	4.90	4.90	2.67	107,282
#9 Boiler	#9 Boiler	92	54.1	3.54	4.90	4.90	2.67	107,282
#10 Boiler	#10 Boiler	39.0	77.4	5.07	7.00	7.00	9.17	153,484
CDU Atmospheric Tower Heater	CDU H-1	151	115	7.56	10.4	10.4	30.9	228,868
CDU #1 Vacuum Tower Heater	CDU H-2	35.0	28.9	1.89	2.61	2.61	46.7	57,217
CDU #2 Vacuum Tower Heater	CDU H-3	18.9	15.6	1.02	1.41	1.41	2.68	30,897
Unifiner Charge Heater	Unifiner H-2	24.1	13.2	0.87	1.20	1.20	1.69	26,248
Unifiner Stripper Reboiler	Unifiner H-3	39.1	21.5	1.41	1.94	1.94	2.46	42,555
No. 2 Platformer Charge Heater	#2 Plat PH-3	23.8	13.1	0.86	1.18	1.18	1.53	25,962
No. 2 Platformer Charge Heater	#2 Plat PH-4	19.6	16.2	1.06	1.46	1.46	1.91	32,041
Coker Drum Charge Heater	Coker B-1	23.7	21.6	1.42	1.96	1.96	1.07	42,913
Coker Pre-Heater	Coker H-3	12.7	11.6	0.76	1.05	1.05	0.57	23,030
LEU Raffinate Mix Heater	LEU H101	14.7	8.08	0.53	0.73	0.73	1.68	16,021
LEU Extract Mix Heater	LEU H-102	59.1	54.1	3.54	4.90	4.90	167	107,282
LEU Hydrotreater Charge Heater	LEU H-201	14.7	8.08	0.53	0.73	0.73	2.10	16,021
MEK – Wax Free Oil Heater	MEK H-101	53.2	29.2	1.91	2.64	2.64	1.44	57,932
MEK – Soft Wax Heater	MEK H-2	25.8	17.7	1.16	1.60	1.60	3.40	35,045
Loading / Unloading Racks	Multiple	-	-	6.4	0.90	0.11	-	-
Tanks	Multiple	-	-	78.3	-	-	-	94.5
Equipment Leaks	---	-	-	169	1.68	1.68	0	248
Wastewater Treatment	---	-	-	196	-	-	-	-

Post-Project Potential To Emit For NO_x, CO, VOC, PM₁₀, PM_{2.5}, and GHG / SO₂ Projected Actual Emissions - Continued

Unit	Point ID	NO _x TPY	CO TPY	VOC TPY	PM ₁₀ TPY	PM _{2.5} TPY	SO ₂ TPY	GHG TPY
HEP (Loading Terminal)								
New Tanks	Multiple	-	-	22.1	-	-	-	29.0
New Equipment Leaks	16	-	-	5.91	-	-	-	348
Loading/Unloading Racks (excluding Terminal)	---	-	-	3.62	-	-	-	-
Tanks	Multiple	-	-	156	-	-	-	10.4
Loading Terminal	6275	14.8	37.1	37.5	1.48	1.48	0.39	11,518
Fugitives	16	-	-	2.56	0.27	0.027	-	334
TOTAL POST-PROJECT EMISSIONS		1,599.09	2,087.24	1,294.88	218.03	216.75	383.07	3,393,823

Project Emissions Changes

Pollutant	PAE TPY	BAE TPY	Difference TPY	PSD Levels of Significance, TPY	Netting Required?
NO _x	1,599.09	791.89	807.20	40	Yes
CO	2,087.24	883.41	1,203.83	100	Yes
VOC	1,294.88	1146.33	148.55	40	Yes
PM ₁₀	218.03	103.05	114.98	15	Yes
PM _{2.5}	216.75	100.20	116.55	10	Yes
SO ₂	383.07	287.07	96.00	40	Yes
GHG	3,393,823	1,357,638	2,036,185	75,000	Yes

PSD Netting

Project	NO _x TPY	CO TPY	VOC TPY	PM ₁₀ TPY	PM _{2.5} TPY	SO ₂ TPY	GHG TPY
Projected Actual Emissions	1,599.09	2,087.24	1,294.88	218.03	216.75	383.07	3,393,823
Baseline Actual Emissions	-791.89	-883.41	-1146.33	-103.05	-100.20	-287.07	-1,357,638
East CDU Atmospheric Tower Heater	-51.8	-14.5	--	--	--	--	--
East Removed Tanks	--	--	-0.79	--	--	--	-62
East Wastewater Treatment Improvements	--	--	-20.0	--	--	--	--
HEP Removed Tanks	--	--	-38.8	--	--	--	--
HEP Removed Thermal Oxidizer	-2.47	-6.18	-8.00	-0.56	-0.56	--	--
HEP Added Tanks	--	--	8.33	--	--	--	10.4
Vapor Combustor	14.8	37.1	37.45	1.48	1.48	0.39	9,214
West Wastewater Treatment Improvements	--	--	-20.0	--	--	--	--
West Removed Tanks	--	--	-57.4	--	--	--	--
West Heaters – Subpart J to Subpart Ja Fuel	--	--	--	--	--	-42.79	--
West Boilers 3 and 4 Removed	-196	-57.7	-3.78	-5.22	-5.22	-20.7	-91,495
West PDA Propane Compressor Electrified	-0.86	-3.44	-1.00	-0.17	-0.17	-0.01	-1,089
West Unifiner H2 Recycle Compressor Electrified	-0.35	-4.62	-1.34	-0.23	-0.23	-0.01	-1,462
West Plat PH-1/2 Heater Removed	-31.5	-17.3	-1.13	-1.56	-1.56	-5.89	-27,415
West Plat PH-5 Heater Removed	-17.4	-11.3	-0.74	-1.02	-1.02	-0.01	-17,861
West Plat PH-6 Heater Removed	-7.69	-4.81	-0.32	-0.44	-0.44	-0.01	-7,632
West Plat PH-7 Heater Removed	-3.65	-2.00	-0.13	-0.18	-0.18	-0.68	-3,177
West #2 Cooling Tower Circulating Pump Electrified	-0.74	-2.94	-0.85	-0.15	-0.15	--	-189
West #3 Cooling Tower Circulating Pump Electrified	-1.78	-7.11	-2.07	-0.36	-0.36	-0.01	-19.3
West #6 Cooling Tower Spray Pump Electrified	-2.04	-8.14	-2.37	-0.41	-0.41	-0.01	--
West #6 Cooling Tower Circulating Pump Electrified	-0.83	-3.32	-0.97	-0.17	-0.17	--	--
West #3 Cooling Tower Replacement	--	--	-3.68	-5.12	-0.03	--	--
	--	--	3.68	3.30	0.02	--	--
West #10 Boiler	39.0	77.4	5.07	7.00	7.00	9.17	122,788
NET EMISSIONS CHANGES	543.89	1,175	39.71	111.17	114.55	35.44	2,017,796
Full PSD Review Required?	Yes	Yes	No	Yes	Yes	No	Yes

SECTION VI. BACT REVIEW

OAC 252:100-8-31 states that BACT “*means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification which the Director, on a case-by-case basis, taking into account energy, environmental, and economic impacts or other costs, determines is achievable for such source or modification....*” A BACT analysis is required to assess the appropriate level of control for each new or physically modified emission unit for each pollutant that exceeds the applicable PSD Significant Emissions Rate (SER).

The U.S. EPA has stated its preference for a “top-down” approach for determining BACT and that is the methodology used for this permit review. After determining whether any New Source Performance Standard (NSPS) is applicable, the first step in this approach is to determine, for the emission unit in question, the available control technologies, including the most stringent control technology, for a similar or identical source or source category. If the proposed BACT is equivalent to the most stringent emission limit, no further analysis is necessary.

If the most stringent emission limit is not selected, further analyses are required. Once the most stringent emission control technology has been identified, its technical feasibility must be determined; this leads to the reason for the term “available” in Best Available Control Technology. A technology that is available and is applicable to the source under review is considered technically feasible. A control technology is considered available if it has reached the licensing and commercial sales stage of development. In general, a control option is considered applicable if it has been, or is soon to be, developed on the same or similar source type. If the control technology is feasible, that control is considered to be BACT unless economic, energy, or environmental impacts preclude its use. This process defines the “best” term in Best Available Control Technology. If any of the control technologies are technically infeasible for the emission unit in question, that control technology is eliminated from consideration.

The remaining control technologies are then ranked by effectiveness and evaluated based on energy, environmental, and economic impacts beginning with the most stringent remaining technology. If it can be shown that this level of control should not be selected based on energy, environmental, or economic impacts, then the next most stringent level of control is evaluated. This process continues until the BACT level under consideration cannot be eliminated by any energy, environmental, or economic concerns.

The five basic steps of a top-down BACT review are summarized as follows:

- Step 1. Identify Available Control Technologies
- Step 2. Eliminate Technically Infeasible Options
- Step 3. Rank Remaining Control Technologies by Control Effectiveness
- Step 4. Evaluate Most Effective Controls Based on Energy, Environmental, and Economic impacts
- Step 5. Select BACT and Document the Selection as BACT

In Step 1 in a “top down” analysis, all available control options for the emission unit in question are identified. Identifying all potential available control options consists of those air pollution control technologies or control techniques with a practical potential for application to the emission unit and the regulated pollutant being evaluated.

In Step 2, the technical feasibility of the control options identified in Step 1 are evaluated and the control options that are determined to be technically infeasible are eliminated. Technically infeasible is defined where a control option, based on physical, chemical, and engineering principles, would preclude the successful use of the control option on the emission unit under review due to technical difficulties. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

Step 3 of the “top-down” analysis is to rank all the remaining control options not eliminated in Step 2, based on control effectiveness for the pollutant under review. If the BACT analysis proposes the top control alternative, there would be no need to provide cost and other detailed information. Once the control effectiveness is established in Step 3 for all feasible control technologies identified in Step 2, additional evaluations of each technology, based on energy, environmental, and economic impacts, are considered to make a BACT determination in Step 4. The energy impact of each evaluated control technology is the energy benefit or penalty resulting from the operation of the control technology at the source. The costs of the energy impacts either in additional fuel costs or the cost of lost power generation impacts the cost-effectiveness of the control technology.

The second evaluation to be reviewed for each control technology remaining in Step 4 is the environmental evaluation. Non-air quality environmental impacts are evaluated to determine the cost to mitigate the environmental impacts caused by the operation of a control technology. The third evaluation addresses the economic evaluation of the remaining control technologies. The cost to purchase and to operate the control technology is analyzed. The capital and annual operating costs are estimated based on established design parameters or documented assumptions in the absence of established designed parameters. The cost-effectiveness describes the potential to achieve the required emission reduction in the most economical way. It also compares the potential technologies on an economic basis.

In Step 5, BACT is selected for the pollutant and emission unit under review. BACT is the highest ranked control technology not eliminated in Step 4. The U.S. EPA has consistently interpreted statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether it is conducted in a “top-down” manner. First, the BACT analysis must include consideration of the most stringent available control technologies, i.e., those that provide the maximum degree of emission reduction. Second, any decision to require a lesser degree of emission reduction must be justified by an objective analysis of energy, environmental, and economic impacts. As stated in the BACT definition, in no case can the maximum available emission rate for the sources exceed the New Source Performance Standard (NSPS) emission rate for the source, or cause an exceedance of the National Ambient Air Quality Standards (NAAQS). Therefore, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate below

those specified by the NSPS and the ambient impact cannot exceed the NAAQS. The new or modified emission sources for this project that are subject to BACT are new process heaters, and new components that will be installed for new or modified process units.

Potentially applicable emission control technologies were identified by researching PSD permits recently issued by ODEQ for the ConocoPhillips Ponca City Refinery and other refineries, the U.S. EPA control technology database, technical literature, control equipment vendor information, and by using process knowledge and engineering experience. Manufacturers were contacted to provide information regarding emission guarantees. The RACT/BACT/LAER Clearinghouse (RBLC), a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies that have been approved in PSD permits as BACT for numerous types of process units. Process units in the database are grouped into categories by industry. Additional sources of potentially applicable emission control technologies include the California Air Resource Board (CARB) BACT determinations database. These sources were reviewed in order to supplement ODEQ permit review, vendor information, and RBLC search results.

Technical literature and guidance documents consulted for the BACT evaluations include:

- New Source Review Workshop Review Manual (Draft, October 1990);
- EPA's "Alternate Control Techniques Document for NO_x Emissions" (June 1994);
- EPA's Air Pollution Technology Fact Sheets (2003);
- Emission Estimation Protocol for Petroleum Refineries, Version 2.1.1 (May 2011);
- EPA's Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources (AP-42, January 1995);
- PSD and Title V Guidance for Interim Permitting Guidance for Greenhouse Gases (March 2011); and
- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Industry (October 2010).

A. New / Modified Process Heaters

1. NO_x BACT Review

The CDU Atmospheric Tower Heater (248 MMBTUH) will have a decrease in NO_x emissions, therefore, is not part of this analysis.

NO_x emissions are generated from the high temperature dissociation of atmospheric nitrogen molecules and their subsequent reaction with oxygen to form nitrogen oxide (NO) or nitrogen dioxide (NO₂) (thermal NO_x) and from chemically bound nitrogen in the fuel (fuel NO_x). Thermal NO_x is primarily formed at temperatures above 2,400°F; therefore, limiting the temperature of the flame can control its generation. Fuel NO_x is formed when the fuel nitrogen is converted to hydrogen cyanide and then oxidized to form NO that further oxidizes in the atmosphere to NO₂. Since the first step of the oxidation occurs in the combustion chamber, providing an oxygen-deficient atmosphere in the combustion chamber can significantly reduce NO, and thereby NO₂ formation. Some combustion processes can be modified to minimize NO_x

emissions by reducing peak flame temperature, gas residence time in the flame zone, and oxygen concentration in the flame zone.

Step 1. Identify Available Control Technologies

A variety of technologies and techniques exist for control of NO_x emissions from process heaters, which have the primary purpose of transferring heat to a process through exchangers. These include add-on control devices, and techniques to minimize NO_x formation. The following is a list of equipment and add-on control technologies that were identified for controlling NO_x emissions from process heaters and boilers.

- Low-NO_x burners (LNB);
- Ultra Low-NO_x Burners (ULNB);
- Flue Gas Recirculation (FGR);
- Selective Non-Catalytic Reduction (SNCR);
- Non-Selective Catalytic Reduction (NSCR);
- Selective Catalytic Reduction (SCR); and
- EMXTM/SCONOX.

These technologies can be used alone or in combination, along with good combustion practices, to minimize NO_x emissions. For example, lower emitting burners can be combined with add-on controls or combustion techniques, such as ULNB with SCR or SNCR, LNB with SCR or SNCR, and LNB with FGR.

Step 2. Eliminate Technically Infeasible Options

The Step 1 technologies were reviewed to determine which are technically feasible, to eliminate technically infeasible options. Some options have significant limitations in refining applications as compared to other technologies that render them infeasible and remove them from further consideration. These include EMX/SCONOX, NSCR, and FGR.

EMXTM/SCONOX

The EMXTM catalyst is the latest generation of SCONOX technology. EMXTM is a multi-pollutant catalyst that does not require ammonia. While this technology has been demonstrated on units firing pipeline quality natural gas, there is no practical experience with operating on flue gas streams from refinery gas-fired equipment. At this time, EMXTM is not being used in any commercial refinery situation with equipment using a sulfur-bearing fuel gas stream such as refinery fuel gas because SO₂ will contaminate the catalyst and reduce efficiency over time. Additionally, the mechanical complexity of EMXTM increases in rough proportion to the heat duty rating of the unit. For larger commercial scale units, a large number of mechanical dampers must operate reliably every several minutes under hot and corrosive conditions to divert the flow of flue gas and regenerating hydrogen gas through segments of the catalyst beds. The challenge presented by this demanding design feature is aggravated by the fact that refinery fuel gas combustion products have a higher potential corrosive acid concentration than natural gas combustion products.

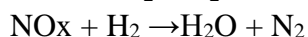
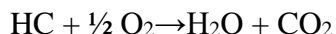
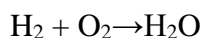
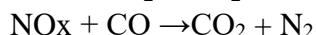
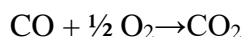
The specified EMX™ catalyst operating temperature range of 300 to 700°F is also a practical limitation for use with refinery process heaters. The typical exhaust temperature range is significantly higher for refinery process heaters and boilers. The EMX™ catalyst technology is not usable unless the tolerated temperature range is increased or the exhaust temperature of the heaters is controlled.

EMX™ also creates an increase in system pressure drop that results in a substantial operating cost penalty. It is estimated that the net power incremental requirement due to higher catalyst bed pressure drop is about 1.8 times that associated with a comparable SCR system.

Because of the lack of commercial refinery experience, the catalyst's sensitivity to sulfur compounds, and mechanical limitations, EMX™ is deemed to be technically infeasible for the refinery process heaters.

Non-Selective Catalytic Reduction (NSCR)

NSCR is a flue gas treatment technology that is similar to the catalytic controls on modern automobiles. Precious metal catalysts, such as platinum, are used to promote reactions that reduce most nitrogen oxides (NO) in the exhaust gases to molecular nitrogen (N₂). Likewise, the catalyst will simultaneously convert over 98% of the NO_x and CO and most of the unburned HC emissions according to the NSCR [unbalanced] reactions below:



These reactions can only occur in this manner when the oxygen content of the exhaust is controlled to less than 1% vol. (typically about 0.5% vol.), which is accomplished by attaching an air/fuel controller (lambda sensor) to maintain the chemically correct (or stoichiometric) air/fuel ratio (AFR), such that all the fuel and oxygen in the mixture are consumed on combustion, and is typically referred to as a rich-burn or stoichiometric operation. The formulas above show that CO must be present in the exhaust gas in order for the NO_x to be reduced to N₂. The refinery heaters operate in a lean burn (i.e., oxygen rich) environment where the O₂ content is substantially greater than 1% vol. There would not be enough CO present in the exhaust stream to effectively react the NO_x to N₂. In addition, oxygen will adsorb on the catalyst and block the reaction. Therefore, NSCR is deemed technically infeasible for the refinery heaters and boilers.

FGR

Flue gas recirculation (recovery) involves the recycling of fuel gas into the air-fuel mixture at the burner to help cool the burner flame. Internal FGR, used primarily in ULNB, involves recirculation of the hot O₂-depleted flue gas from the heater into the combustion zone using burner design features. External FGR, usually used with LNB, requires the use of hot-side fans and ductwork to route a portion of the flue gas in the stack back to the burner wind box. Flue gas recirculation has not been demonstrated to function efficiently on process heaters that are subject

to highly variable loads and that burn fuels with variable heat value. There are significant technical differences between the proposed process heaters and those combustion sources where flue gas recirculation has been demonstrated in practice. Thus, FGR has been eliminated as BACT for NO_x reduction for the new process heaters proposed by Holly.

Step 3. Rank Remaining Control Technologies by Control Effectiveness

The remaining options are ranked based on effectiveness.

Technology	Control Efficiency %
ULNB + SCR	85-99
LNB + SCR	80-99
ULNB + SNCR	75-95
LNB + SNCR	50-99
LNB	<40
ULNB	70-90
SCR	70-90
SNCR	30-50
LNB	<40
No control	---

Step 4. Evaluate Remaining Options

The remaining top-ranked technologies are evaluated in this section, including their effectiveness, and any energy, environmental, and economic impacts.

LNB

The use of LNB is often considered as a baseline NO_x control technology, since most heaters and boilers in the refining industry are capable of being equipped with LNB. LNB technology uses advanced burner design to reduce NO_x formation through the restriction of oxygen, flame temperature, and/or residence time. The two types of LNB include staged fuel and staged air burners. Staged fuel burners are particularly useful for NO_x reduction in refinery process heaters. The burners separate the combustion zone into two regions, with lower combustion temperature in the first zone that reduces overall oxygen, with fuel injected into the second zone to reduce overall formation of thermal NO_x. A NO_x emission rate of 0.08 lb/MMBTU is typically considered an average emission rate for LNB technology. As a stand-alone control technology for a new heater, ULNB would be considered more effective for NO_x emission control. However, LNB can be considered in conjunction with other add-on controls.

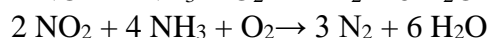
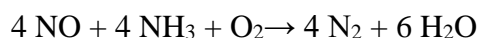
ULNB

There are several designs of ULNB currently available. These burners combine two NO_x reduction steps into one burner; typically staged air with internal flue gas recirculation (IFGR) or staged fuel with IFGR, without any external equipment. In staged air burners with IFGR, fuel is mixed with part of the combustion air to create a fuel rich zone. High-pressure atomization of the fuel creates the recirculation. Secondary air is routed by means of pipes or ports in the burner block to optimize the flame and complete combustion. Thus the average oxygen concentration is reduced in the flame without reducing the flame temperatures below that which is necessary for optimal combustion efficiency. This design is predominately used with liquid fuels. Modern

ULNB technology is available at a NO_x emission rate of 0.03 lb/MMBTU for the size range of new process heaters proposed for the project.

SCR alone or SCR with ULNB or LNB

SCR is a post-combustion NO_x control technology. In SCR, ammonia (NH₃) diluted with air or steam is injected into the flue gas upstream of a catalytic reactor. On the catalyst surface, the NH₃ reacts with NO_x to form molecular nitrogen and water.



The SCR process requires a reactor vessel, a catalyst, and an ammonia storage and injection system. The SCR system requires ammonia in the presence of a catalyst. The presence of the catalyst effectively reduces the ideal reaction temperature for NO_x reduction to between 475 and 850°F and increases the surface area available for NO_x reduction. As a postcombustion process, the SCR system is usually installed to receive flue gas after it has left the combustion chamber. The exact location of the SCR reactor will vary depending upon what other type of pollution control systems are also present. Therefore, the applicability of SCR is limited to heaters that have both a flue gas temperature appropriate for catalytic reaction and space for the catalyst bed large enough to provide sufficient residence time for the reaction to occur. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_x concentration, the exhaust temperature, the ammonia injection rate, the type of catalyst, and the presence of catalyst poisons, such as particulate matter and SO₂.

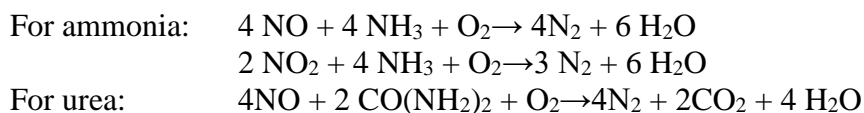
The EPA report “BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic compounds at Tier 2/Gasoline Sulfur Refinery Projects” (John Seitz, January 19, 2001) served as the basis for SCR cost effectiveness calculations. The complete report, including economic analyses, is available at www.epa.gov/region7/air/nsr/nsrmemos/t2bact.pdf. The EPA report analyzed four burner sizes (10, 50, 75, and 150 MMBTUH) which are comparable to heaters proposed in this application. 90% NO_x control was evaluated. Costs were then increased by the consumer price index relative to 2001, a factor of 1.336. The costs, \$/ton, decrease as unit size increases, but all costs exceeded \$10,000 per ton additional NO_x controlled over ULNB. It is agreed that these costs are excessive and SCR may be rejected.

Burner Size	Incremental Costs of SCR (\$/ton) 2014 \$
10	43,920
50	15,333
75	12,641
150	10,369

Catalyst systems promote partial oxidation of hydrogen sulfide to sulfur dioxide which combines with water to form sulfur trioxide and sulfuric acid (H_2SO_4). SCR units typically achieve 70 to 90% NO_x reduction with an ammonia exhaust concentration (ammonia slip) of 5 to 10 parts per million by volume on a dry basis (ppmvd) at 15% oxygen. Additional environmental concerns are caused by the formation of secondary particulate from the ammonia reagent. The phenomenon can be more pronounced as ammonia injection rates must be increased and ammonia slip increases as the catalyst deactivates over time. There are also safety issues with the transportation, handling and storage of ammonia. Ammonia is a toxic substance whose storage above certain quantities requires the development of a Risk Management Plan (RMP). SCR can be used in combination with ULNB or LNB to increase overall NO_x control efficiency to greater than 90%. While use of SCR can marginally increase NO_x control effectiveness over LNB or ULNB technology, SCR has significant technical, economic, energy and environmental impacts, and thus, has been eliminated from consideration.

SNCR alone or SCNR with ULNB or LNB

SNCR describes a process by which NO_x is reduced to molecular nitrogen (N_2) by injecting an ammonia or urea ($\text{CO}(\text{NH}_2)_2$) spray into the post-combustion area of the unit. Typically, injection nozzles are located in the upper area of the furnace and convective passes. Once injected, the urea or ammonia decomposes into NH_3 or NH_2 free radicals, reacts with NO_x molecules, and reduces to nitrogen and water. These reactions are endothermic and use the heat of the burners as energy to drive the reduction reaction. The ammonia and urea reduction equations are shown following.



Both ammonia and urea have been successfully employed as reagents in SNCR systems and have certain advantages and disadvantages. Ammonia is less expensive than urea and results in substantially less operating costs at comparable levels of effectiveness. Urea, however, is able to penetrate further into flue gas streams, making it more effective in larger scale burners and combustion units with high exhaust flow rates. In addition, ammonia is a toxic substance whose storage above certain quantities requires the development of a Risk Management Plan (RMP). SNCR is considered a selective chemical process because, under a specific temperature range, the reduction reactions described above are favored over reactions with other flue gas components. Although other operating parameters such as residence time and oxygen availability can significantly affect performance, temperature remains one of the most prominent factors affecting SNCR performance.

The EPA report “BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Sulfur Refinery Projects” (John Seitz, January 19, 2001) served as the basis for SNCR cost-effectiveness calculations. SNCR was considered by EPA in the draft version of this report (issued for public comment March 14, 2000) and available at www.epa.gov/NSR/ttnsr01/gen/refbact.pdf. SNCR was discarded from the final version of this report since SNCR alone was found to be inferior to ultralow NO_x burner (at a higher cost) and SNCR plus ultralow NO_x burner was found to be economically inferior to SCR plus ultralow

NOx burner. In addition, the combination of SNCR plus ultralow NOx burner had not been demonstrated so the performance level is uncertain. For purposes of our current application the SNCR costs are taken from the March 14, 2000 draft report and updated in the same manner that SCR costs were updated for the January 19, 2001 final report (the main update being the inclusion of a 1.5% fuel penalty). The control level from these reports of 0.015 lb NOx/MMBTU for SNCR plus ultralow NOx burner has not been demonstrated, but is assumed in the cost-effectiveness calculations. Three burner sizes were analyzed for costs using the factors in the EPA report, all with excessive costs for NOx control:

Burner Size	Incremental Costs of SNCR (\$/ton) 2014 \$
50	25,648
75	22,589
125	19,610

The SNCR process requires the installation of reagent storage facilities, a system capable of metering and diluting the stock reagent into the appropriate solution, and an atomization/injection system at the appropriate locations in the combustion unit. The reagent solution is typically injected along the post-combustion section of the combustion unit. Injection sites around the unit must be optimized for reagent effectiveness and must balance residence time with flue gas stream temperature. For ammonia, the optimum reaction temperature range is 1,600 to 2,000°F, while optimum urea reaction temperature ranges are marginally higher at 1,650 to 2,100°F. Although the overall chemistry is identical to that used in the SCR system, the absence of a catalyst results in several differences. The un-catalyzed reaction requires a higher reaction temperature and is not as effective. SCR can be used in combination with ULNB or LNB to increase overall NOx control efficiency to greater than 75-90%. While use of SNCR can marginally increase NOx control effectiveness over LNB or ULNB technology, and the technology is more economical than SCR with fewer energy and environmental impacts, the technology is still not considered economically cost-effective, and thus, has been eliminated from consideration.

Step 5. Select BACT and Document the Selection as BACT

The proposed heaters for this project are small (< 100 MMBTUH) and are related to process units downstream of crude units. The following table presents a summary of selected BACT determinations for NOx emissions for similar process heaters within the last six years. The RBLC database indicates both proposed and achieved in practice emission rates of 0.03 to 0.08 lb/MMBTU NOx for similar sized units using ULNB and LNB technology and less than 100 MMBTUH. The RBLC does contain heaters with lower emission limits (i.e., 0.0125 to 0.02 lb/MMBTU), but these heaters utilize SCR controls, are large, and are mainly in nonattainment areas. Since ULNB provides the highest remaining feasible control, BACT has been proposed as ULNB at an emission rate of 0.03 lb/MMBTU for the new process heaters. SCR and NSCR are economically infeasible and have adverse energy and environmental impacts given the size and nature of the proposed heaters. Therefore, the proposed ULNB controls with an emission factor of 0.03 lb /MMBTU NOx is selected as BACT.

Summary of BACT Determinations for NO_x for Process Heaters, <100 MMBTUH

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
HRMT Woods Cross Refinery, UT	n/a	DAQEIN1012 3 0041-12	July 2012	New - Reactor Charge Heater, FCCU #2 Feed Heater, Asphalt Heaters, Heater Oil Furnace	42.1, 45, 0.8, 14	Refinery fuel gas	0.04 (3-hour average)	ULNB
Sinclair Refinery	WY-0071	MD-12620 (draft)	10/15/12	New - BSI Heater	50	Refinery fuel gas	0.025 (3-hr average)	ULNB
Sinclair Refinery	WY-0071	MD-12620 (draft)	10/15/12	Existing Naphtha Splitter Heater; Hydrocracker H5 Heater; #1 HDS Heater	46.3 44.9 33.4	Refinery fuel gas	0.035 (3-hr average)	ULNB
Valero Refining St. Charles Refinery	LA-0213	PSD-LA-619(M-5) (draft)	11/17/09	CPF Heaters H-39-03 and H-39-02	68	Refinery fuel gas	0.05 (3 one-hr test average)	ULNB
Valero Refining St. Charles Refinery	LA-0213	PSD-LA-619(M-5) (draft)	11/17/09	Heaters 2008-1 - 2008-9	36	Refinery fuel gas	0.03 (no preheat) or 0.04 (air preheated) (3 one-hr test average)	ULNB

Summary of BACT Determinations for NO_x for Process Heaters, <100 MMBTUH - Continued

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Valero Refining St. Charles Refinery	LA-0213	PSD-LA-619(M-5) (draft)	11/17/09	DHT Heaters 4-81, 5-81	70	Refinery fuel gas	0.08 (3 one-hr test average)	ULNB
Hunt Refinery Tuscaloosa	AL-0242	X063A X066A X067A X070A	9/28/09	Existing modified process heaters	57 49.4 34.7 98.3 69.3 78.2 60.9 254	Refinery fuel gas	0.035	ULNB
Chevron Products Company, Pascagoula Refinery	MS-0089	1280-00058	4/14/09	Lube Hydrocracker Feed Heater Ck-003; Feed Preparation Unit Vacuum Column Feed Heater Ck- 004; IDW/HDF Reactor Feed Heater CK- 005; IDW/HDF Vacuum Column Feed Heater CK- 006	73.25 73.95 54.53 51	Refinery fuel gas	0.045 (3-hr rolling average); 0.03 (30 day average)	ULNB

Summary of BACT Determinations for NOx for Process Heaters, <100 MMBTUH - Continued

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
ConocoPhillips, Ponca City Refinery	OK-0136	2007-042-C PSD	2/09/09	NH-1 New Naphtha Splitter Reboiler, NH-3 CTU Vacuum Heater, NH-4 CTU Crude Heater, NH-5 CTU Tar Stripper Heater	131.3, 45, 125, 98	Refinery fuel Gas	0.03 (annual average)	ULNB
Sunoco Inc., Tulsa Refinery	OK-0126	98-014-C (M-14) (PSD permit was cancelled)	5/27/08	Process heaters	44 57.3	Refinery fuel gas	0.03 (3-hr average)	ULNB
Navajo Refining Company, Artesia Refinery	NM-0050	PSD-NM-195-M25	12/14/07	Sulfur recovery hot oil heater	9.6, 9.6, 35, 120	Refinery fuel gas	0.03 (3-hr rolling average)	ULNB
Marathon Petroleum Co., Garyville Refinery	LA-0211	PSD-LA-719	12/27/06	Platformer Heater Cells No. 1-3	75.7, 138.4, 73.8, 121.8, 85.1, 85.1	Refinery fuel gas	0.03 (annual average)	ULNB

2. CO BACT Review

The CDU Atmospheric Tower Heater (248 MMBTUH) will have a decrease in CO emissions, therefore, is not part of the CO analysis.

Carbon monoxide is a product of the chemical reaction between carbonaceous fuels and oxygen. CO occurs as the product of combustion in fuel-rich mixtures. In fuel-lean mixtures, CO can result due to poor mixing of fuel and air or because of low temperatures in the combustion zone.

Step 1. Identify Available Control Technologies

A search of the RBLC and literature sources identified the following technologies for control of CO emissions from process heaters:

- Good Combustion Practice;
- Ultra-Low NOX Burners (ULNB);
- Regenerative Thermal Oxidation (RTO); and
- Regenerative Catalytic Oxidation (RCO).

Good Combustion Practice

Good combustion practice includes operational and design elements to control the amount and distribution of excess air in the flue gas. This ensures that there is enough oxygen present for complete combustion. If sufficient combustion air, temperature, residence time, and mixing are incorporated in the combustion design and operation, CO emissions are minimized. The design of modern, efficient combustion equipment is such that there is adequate turbulence in the flue gas to ensure good mixing, a high temperature zone (greater than 1,800°F) to complete burnout, and sufficient residence time at the high temperature (one to two seconds). Good combustion practice is the industry standard for CO control of process heaters and boilers. Operators control CO emissions by maintaining various operational combustion parameters. Modern combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions.

ULNB

ULNB technology has developed to provide increasing lower levels of NO_x emissions. However, when operated using good combustion practices, ULNB can also provide significant reductions in CO emissions.

Regenerative Thermal Oxidation

Thermal oxidizers combine temperature, time, and turbulence to achieve complete combustion. Thermal oxidizers are equivalent to adding another combustion chamber where more oxygen is supplied to complete the oxidation of CO. The waste gas is passed through burners, where the gas is heated above its ignition temperature. Thermal oxidation requires raising the flue gas temperature to 1,300 to 2,000°F in order to complete the CO oxidation. Depending on specific furnace and thermal oxidizer operational parameters (fuel gas heating value, excess oxygen in the flue gas, flue gas temperature, and oxidizer temperature) raising the flue gas temperature can require an additional heat input of 10 to 25% above the process heater heat input. Also,

depending on the design of the thermal oxidizer, emissions of SO₂, NO_x and PM₁₀ / PM_{2.5} can be 10 to 25% higher than emissions without a thermal oxidizer.

Regenerative Catalytic Oxidation

Catalytic oxidation allows complete oxidation to take place at a faster rate and a lower temperature than is possible without the catalyst. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 feet per second (fps) to 30 fps. Catalytic oxidizers typically operate at 650 to 1,000°F. This can require from 0 to 10% additional fuel and a resulting similar increase in other pollutant emissions. Catalytic oxidizers cannot be used on waste gas streams containing significant amounts of particulate matter as the particulate deposits foul the catalyst and prohibit oxidation. High temperatures can also accelerate catalyst deactivation; however, that is normally not a concern with flue gas from process heaters and boilers.

Step 2. Eliminate Technically Infeasible Options

A search of the RBLC database indicated that thermal and catalytic oxidation has rarely been applied to process heaters or boilers. Typically, higher concentrations of CO in the pollutant stream are needed to justify the use of thermal oxidation and catalytic oxidation. However, neither control option can be eliminated as technically infeasible. Therefore, all of the technologies mentioned above will be examined for energy, environmental, and economic impacts.

Step 3. Rank Remaining Control Technologies by Control Effectiveness

The remaining options are ranked based on effectiveness.

Technology	Control Efficiency %
Good Combustion Practices	Base case
ULNB	25-75
Regenerative Thermal Oxidizer	75-95
Regenerative Catalytic Oxidation	75-95

Step 4. Evaluation of Remaining Control Technologies Based on Energy, Environmental, and Economic Impacts

The technologies for CO emission controls are evaluated in this section, including their effectiveness, and any energy, environmental, and economic impacts.

A review of BACT determinations for refinery heaters did not identify the use of add-on controls as achieved in practice. Instead, low-NO_x burners have been used – many which also provide for low CO emissions.

A range of costs is based on EPA's Air Pollution Control Technology Fact Sheet for regenerative incinerators (www.epa.gov/ttn/catc/dir1/fregen.pdf). From a baseline of 0.082 lb CO/MMBtu (AP-42), the proposed ultralow-NOx burners will reduce emissions to an estimated 0.04 lb CO/MMBtu. For cost-effectiveness calculations it is assumed that the RTO or RCO can reduce CO by an additional 90%. The add-on control equipment is sized based on air flow, which varies from about 2,000 scfm for a 10 MMBtu/hr heater to 27,000 scfm for a 125 MMBtu/hr heater. Annualized costs [2002 basis] have been estimated to range from \$8 - \$33 per scfm for an RTO and \$11 - \$42 per scfm for a RCO. Using the average of the ranges, the incremental cost effectiveness is determined to be approximately \$37,500/ton CO controlled by an RTO and approximately \$48,500/ton CO controlled by a RCO. There is no bright line rule for cost-effectiveness of CO controls, but since incremental cost effectiveness of the add-on controls is two orders of magnitude greater than the cost effectiveness of for the ultra-low NOx burner the RTO and RCO control costs are not considered cost effective.

RTO

Installation costs and operating costs for RTO (mostly from the 10 to 25% increase in fuel consumption) can be significant. In addition, the use of a thermal oxidizer can significantly increase the emissions of NOx from the process heaters. A search of the RBLC indicated that thermal oxidation has not been selected as BACT for control of CO from small process heaters. Therefore, based on the additional use of energy, the increase in emissions of other pollutants, the associated costs, and no previous documentation of thermal oxidation as BACT; thermal oxidation is eliminated from further consideration.

RCO

Cost levels for RCO are also considered to be economically infeasible for BACT. Also, an environmental consideration is the disposal of spent catalyst, which is considered a hazardous material. A search of the RBLC and recently issued permits in attainment areas indicated that catalytic oxidation was rarely selected as BACT. Therefore, based on the additional use of energy, the possible increase in emissions of other pollutants, the associated costs, and no previous documentation of catalytic oxidation as BACT; catalytic oxidation is eliminated from consideration as BACT for this project.

UNLB

The proposed heaters for this project are small (<100 MMBTUH) and are related to process units downstream of crude units. The following table presents a summary of selected BACT determinations for CO emissions for similar process heaters within the last six years. A review of the RBLC database indicated that use of ULNB was selected as BACT for a number of PSD permits. These determinations were usually made on the basis that use of ULNB was BACT for NOx and would also be selected as BACT for CO. As the ULNB technology has achieved lower emissions of NOx, the burners have also provided lower emissions of CO. Recent BACT determinations for small process heaters <100 MMBTUH with ULNB and/or good combustion practices have shown CO emissions ranging from 0.04 to 0.08 lb/MMBTU.

Good Combustion Practices

Good combustion practice is the industry standard for CO control of process heaters and boilers. Operators control CO emissions by maintaining various operational combustion parameters. Modern combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions. There is no increased energy requirement or increased pollutants with good combustion practice. The RBLC database lists this option as a prevalent form of BACT for controlling CO emissions from process heaters and boilers. CO emissions using this method will be 0.04 lb/MMBTU.

Step 5. Select BACT and Document the Selection as BACT

The new process heaters for the project will be equipped with ULNB. Holly will also follow good combustion practices. The combination of ULNB and good combustion practice is selected as BACT, at the emission rate of 0.04 lb CO/MMBTU.

The following regulations contained within 40 CFR 60 were reviewed with regards to the new process heaters, and CO emissions and NO_x emissions discussed in the last section:

- Subpart J – Standards of Performance for Petroleum Refineries;
- Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007; and
- Subpart Dc – Small Industrial-Commercial-Institutional Steam Generating Units that Commenced Construction After June 9, 1989.

NSPS Subpart Ja includes a NO_x emission limit for process heaters with rated capacities greater than 40 MMBTUH of 40 ppm NO_x by volume, dry basis corrected to 0% excess air, on a 24-hour rolling average basis, which is approximately equivalent to 0.042 lbs NO_x/MMBTU. The NO_x emission limit proposed for the new heaters is more stringent, and therefore compliant with the currently-stayed NSPS Subpart Ja limit. Subpart Ja does not include CO limits for fuel gas combustion devices such as the new heaters. NSPS Subpart J does not include NO_x or CO emission limits for fuel gas combustion devices. In addition, the regulations are not applicable to these heaters because of their date of manufacture. Subpart Dc does not include NO_x or CO emission limits for gas-fired boilers. The only requirements for these boilers are initial notification and recordkeeping of the fuel combusted during each calendar month. Lastly, there are no currently applicable MACT standards with limits for NO_x or CO.

Summary of BACT Determinations for CO for Process Heaters, <100 MMBTUH

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
HRMT Woods Cross Refinery, UT	n/a	DAQEIN1012 3 0041-12	July 2012	New - Reactor Charge Heater, FCCU #2 Feed Heater, Asphalt Heaters, Heater Oil Furnace	42.1, 45, 0.8, 14	Refinery fuel gas	0.08 (1-hour average)	ULNB, good combustion practices
Sinclair Refinery	WY-0071	MD-12620 (draft)	10/15/12	Existing Naphtha Splitter Heater; Hydrocracker HS Heater; #1 HDS Heater	50 46.3 44.9 33.4	Refinery fuel gas	0.04 (3-hr average)	ULNB, good combustion practices
Valero Refining St. Charles Refinery	LA-0213	PSD-LA-619(M-5) (draft)	11/17/09	CPF Heaters H-39-03 and H-39-02 Heaters 2008-1 - 2008-9 DHT Heaters 4-81 and 5-81	68 36 70	Refinery fuel gas	0.08 (one-hr average)	ULNB, good combustion practices

Summary of BACT Determinations for CO for Process Heaters, <100 MMBTUH - Continued

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Total Refining – Port Arthur	TX-0539	PSD-TX-1073M1	11/6/09	VDU Heater; KNHT Charge Heater; DHT-3 Charge Heater	99 42 50	Refinery fuel gas	0.07 (one-hr average)	Good burner technology
ConocoPhillips, Ponca City Refinery	OK-0136	2007-042-C PSD	2/09/09	NH-1 New Naphtha Splitter Reboiler	131.3, 45, 125, 98	Refinery fuel Gas	0.04 (annual average)	ULNB, good combustion practices
Navajo Refining Company, Artesia Refinery	NM-0050	PSD-NM-195-M25	12/14/07	ROSE 2 Hot Oil Heater	9.6, 9.6, 35, 120	Refinery fuel gas	0.09 (3-hr rolling average)	ULNB, gaseous fuel combustion only
Marathon Petroleum Co., Garyville Refinery	LA-0211	PSD-LA-719	12/27/06	Platformer Heater Cells No. 1-3, and HCU Fractioner Heater	75.7, 138.4, 73.8, 121.8, 85.1, 85.1	Refinery fuel gas	0.04 (3-run average)	ULNB, proper design, operation, and good engineering practices

Summary of BACT Determinations for PM₁₀ for Process Heaters, <100 MMBTUH

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Navajo Refining Company, Artesia Refinery	NM-0050	PSD-NM-195-M25	12/14/07	Hydrocracker reboiler	35	Refinery fuel gas	0.0075	Nothing stated
Navajo Refining Company, Artesia Refinery	NM-0050	PSD-NM-195-M25	12/14/07	Hydrocracker fractionator furnace	9.6	Refinery fuel gas	0.0075	Nothing stated

3. PM₁₀ & PM_{2.5} Emissions from New / Modified Process Heaters

PM₁₀ is particulate matter (PM) less than 10 microns in diameter produced by combustion. PM₁₀ consists of two parts, filterable and condensable. Filterable PM₁₀ is the material that is captured on the filter used in the EPA Method 5 test. Condensable PM₁₀ is particulate that passes through the filter as a gas and is measured using EPA Reference Method 202. According to AP-42, filterable PM emissions from gaseous fuels such as refinery fuel gas are typically lower than emissions from solid fuels. Particulate matter from refinery gas or natural gas combustion is usually composed of larger molecular weight hydrocarbons that have not been fully combusted. Based upon the literature sources reviewed, nearly all particulate from refinery gas or natural gas combustion sources is PM_{2.5}. Therefore, for the BACT analysis for process heaters, PM_{2.5} and PM₁₀ are considered equivalent.

Widely accepted petroleum industry references and permit determinations support the basis that refinery gas combustion PM is mainly in the PM_{2.5} size range. Industry research has confirmed this fact. In “PM_{2.5} Speciation Profiles and Emission Factors from Petroleum Industry Gas-Fired Sources.” (Wien, England, et. Al., www.epa.gov/ttnchie1/conference/ei10/poster/wien.pdf), it is stated “The majority of primary emissions from combustion is found in the PM_{2.5} or smaller size range, especially for devices equipped with particulate emissions control equipment and for clean burning fuels such as gas.” The Refinery Emissions Estimation Protocol for Petroleum Refineries (Version 2.1.1, May 2011) Section 4.5 recommends calculating PM emissions from refinery gas combustion using EPA AP-42 Section 1.4 emission factors developed for natural gas combustion in boilers and heaters. The condensable PM fraction from Table 1.4-2, assumed to be PM_{2.5}, is 75%. The California Air Resources Board, in PM speciation profiles used for emission inventories (www.arb.ca.gov/ei/speciate/speciate.htm#filelist), cites the fraction of PM emissions less than 2 micron from refinery process heaters as 93%. As a worst-case assumption, all PM₁₀ is assumed to be PM_{2.5}.

Step 1. Identify All Available Control Technologies

The following is a list of control technologies, which were identified for controlling PM₁₀ / PM_{2.5} emissions:

- Good combustion practices;
- Use of low sulfur gaseous fuels;
- Proper design and operation;
- Wet gas scrubber;
- Electrostatic precipitator (ESP);
- Cyclone; and
- Baghouse / fabric filters.

By maintaining the heaters in good working order per manufacturer specifications with low sulfur gaseous fuels, emissions of PM₁₀ / PM_{2.5} are reduced.

A wet gas scrubber is an air pollution control device that removes PM and acid gases from waste streams from stationary point sources. PM and acid gases are primarily removed through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. Wet scrubbers have some advantages over ESPs and baghouses in that they are particularly useful in removing PM with the following characteristics:

- Sticky and/or hygroscopic materials;
- Combustible, corrosive or explosive materials;
- Particles that are difficult to remove in dry form;
- PM in the presence of soluble gases; and
- PM in gas stream with high moisture content.

An ESP is a particle control device that uses electrical forces to move the particles out of the gas stream onto collector plates. This process is accomplished by the charging of particles in the gas stream using positively or negatively charged electrodes. The particles are then collected, as they are attracted to oppositely opposed electrodes. Once the particles are collected on the plates, they are removed by knocking them loose from the plates, allowing the collected layer of particles to fall down into a hopper. Some precipitators remove the particles by washing with water. ESPs are used to capture coarse particles at high concentrations. Small particles at low concentrations are not effectively collected by an ESP.

A cyclone operates on the principle of centrifugal separation. The exhaust enters the top and spirals around towards the bottom. As the particles proceed downward, the heavier material hits the outside wall and drops to the bottom where it is collected. The cleaned gas escapes through an inner tube. Cyclones are generally used to reduce dust loading and collect large particles.

A fabric filter unit (or baghouse) consists of one or more compartments containing rows of fabric bags. Particle-laden gases pass along the surface of the bags then through the fabric. Particles are retained on the upstream face of the bags and the cleaned gas stream is vented to the atmosphere. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter. Fabric filters are used for medium and low gas flow streams with high particulate concentrations.

Step 2. Eliminate Technically Infeasible Control Options

None of the add-on control devices were identified as being suitable for the process heaters burning gaseous fuels due to both the extremely low concentration of small particulates expected in gas streams from this type of equipment. PM₁₀ / PM_{2.5} concentrations in the refinery fuel and natural gas-fired boilers and heaters are even less than the concentrations guaranteed by the cyclones, ESPs, fabric filters, and wet scrubbers. Therefore, wet scrubbers, ESPs, cyclones, and fabric filtration (baghouses) were rejected as BACT for PM₁₀ / PM_{2.5} emissions from heaters and boilers.

Step 3. Rank Remaining Control Options

The remaining control option is the utilization of good combustion practices.

Step 4. Evaluate Remaining Control Options

The concept of applying combustion controls and appropriate furnace design or “proper combustion” to minimize PM₁₀ / PM_{2.5} emissions include adequate fuel residence time, proper fuel-air mixing, and temperature control to ensure the maximum amount of fuel is combusted. Optimization of these factors for PM₁₀ / PM_{2.5} control can result in an increase in the NO_x emissions. Heater and boiler designers strive to balance the factors under their control to achieve the lowest possible emissions of all pollutants. Thus, the only control technology identified in the RBLC database for the refinery fuel or natural gas-fired process heaters is a work practice requirement to adhere to good combustion practices and use of low sulfur gaseous fuel. This control strategy is technically feasible and will not cause any adverse energy, environmental, or economic impacts.

Step 5. Select BACT

A review of the RBLC as well as other databases indicated that the most stringent control technologies for PM₁₀ / PM_{2.5} are good combustion practices and use of gaseous fuel. Based upon review of the database, the selected PM₁₀ / PM_{2.5} BACT emission limit for the proposed new / modified process heaters is based on manufacturer data at 0.0075 lb/MMBTU PM₁₀ / PM_{2.5}, utilizing proper equipment design and operation, good combustion practices, and gaseous fuels.

4. BACT for New / Modified Process Heaters for Greenhouse Gases

Greenhouse gas (GHG) emissions from process heaters include primarily carbon dioxide (CO₂) with lesser amounts of nitrous oxide (N₂O) and methane (CH₄). The majority of the total GHG emissions, expressed as CO₂e are CO₂ emissions. CO₂ is a product of combustion of fuel containing carbon, such as refinery fuel gas and natural gas. Refinery fuel gas is a mixture of light C1 to C4 hydrocarbons, hydrogen, hydrogen sulfide (H₂S), and other gases.

A search of EPA’s RBLC shows no BACT determinations for gas-fired heaters smaller than 100 MMBTUH.

Step 1. Identify All Available Control Technologies

Control technologies identified for reducing GHG emissions from process heaters include:

- Energy-efficient design and good combustion practices;
- Use of low-carbon fuel;
- Carbon capture and sequestration (CCS).

Post-combustion capture systems use chemical or physical absorption/adsorption processes, which may include solvent scrubbing, high temperature sorbents, ionic liquids, biological capture using algae ponds, and membrane technology.

Step 2. Eliminate Technically Infeasible Control Options

The identified control options of energy efficient design and combustion practices and low-carbon fuels are technically feasible and will be reviewed further. The purpose of carbon capture and sequestration (CCS) is to produce a concentrated stream that can be readily transported to a CO₂ storage site. Options to capture CO₂ emissions include oxy-combustion and post-combustion methods. If either carbon capture technology can be utilized, after capture, a compression system to compress the CO₂ is needed to prepare the CO₂ for transport to a permanent geological storage site such as oil and gas reserves and underground saline formations, and to inject the captured CO₂ into the storage site. In oxy-combustion carbon capture, nearly pure oxygen is used for combustion instead of air which results in an exhaust gas that is comprised of mainly H₂O and concentrated CO₂. The process uses an air separation unit to remove the nitrogen component from the air. The oxygen-rich stream is fed to the combustion unit so the resulting exhaust gas contains a concentration of CO₂ of 80% or higher. This technology is still in the research stage.

In addition to oxy-combustion carbon capture, post-combustion capture systems are currently under commercial development. Post-combustion capture is an “end of pipe” technology that involves separating CO₂ from flue gas consisting mainly of nitrogen, water, CO₂ and other impurities.

Carbon capture technologies are not yet commercially available, and appropriate geologic formations have not been proven for long-term underground storage in the vicinity of Tulsa, OK. It is unlikely that there are existing pipelines running through metropolitan Tulsa available for transporting the CO₂. In addition, collateral environmental impacts that could result from sequestration have not been evaluated and require further study. Therefore, carbon capture and sequestration is not considered to be a demonstrated control option at this time, and is therefore eliminated from further consideration in this analysis. In addition, since CCS is not yet commercially available, it is not possible to accurately estimate control costs.

The nearest CO₂ injection location was researched for determining feasibility of CO₂ injection. The applicant looked up current CO₂ injection projects at <http://www.natcarbviewer.com> sponsored by US Dept of Energy. There is a CO₂ injection study in the development phase about 500 miles to the west in Texas (Chapparral Energy's Farnsworth Unit EOR Field Project), and a small scale injection project sponsored by the University of Kansas about 150 miles to the northwest in the Wellington Field near Wichita, Kansas. Since these injection sites are not commercially available and would require the construction of a lengthy pipeline, they are not considered feasible at this time.

Step 3. Rank Remaining Control Options

The use of energy efficient design and combustion practices and low-carbon fuels to reduce GHG emissions from the proposed new and modified process heaters at Holly will be standard for the proposed project.

Step 4. Evaluate Remaining Control Options

Possible GHG reduction measures and good combustion practices for new process heaters fired on refinery fuel gas include:

- Draft controls can be installed to limit excess air to an optimal level to reduce energy usage of the burners. Regular maintenance of the draft air intake systems can reduce energy usage;
- Air preheating – the flue gases of the furnace can be used to preheat the combustion air and increase the thermal efficiency of the furnace;
- Sufficient residence time to complete combustion;
- Proper fuel gas supply system design and operation; and
- Instrumentation to monitor and control excess oxygen levels in the optimal zone to complete combustion while maximizing thermal efficiency.

To the extent that combustion control and good practices increase fuel efficiency, they are an effective means for reducing CO₂ emissions. Preheating the combustion air reduces the amount of fuel required and ultimately lowers GHG emissions since less fuel is being combusted. Maximizing combustion efficiency through process heater burner design and operation further reduces CH₄ emissions and reduces operating cost.

Low-Carbon Fuel

Gaseous fuels such as refinery fuel gas and natural gas reduce CO₂ emissions from combustion relative to burning solid or liquid fuels such as coal or distillate oils. HRMT will primarily use refinery fuel gas in the new process heaters.

Step 5. Select BACT

The BACT selection for GHG emissions from new process heaters is good combustion practices, use of low-carbon fuel, and energy efficient design. This includes good air/fuel mixing in the combustion zone, good burner maintenance and operation, sufficient residence time to complete combustion, high temperatures and low oxygen levels in the primary combustion zone, proper fuel gas supply system design and operation, and excess oxygen levels high enough to complete combustion while maximizing thermal efficiency. Oxygen monitors and intake airflow monitors will be used to optimize the fuel/air mixture and limit excess air. As available from the manufacturer, air preheater packages will be installed, consisting of a compact air-to-air heat exchanger installed at grade level through which the hot stack gases from the convection section exchange heat with the incoming combustion air.

For a CO₂e BACT emission limitation for new / modified process heaters, HRMT proposes the value be established in terms of lb CO₂/MMBTU, based upon the manufacturer heat input rating and a default refinery gas CO₂ factor emission factor. BACT is selected as a limit of 146 lb CO₂e/MMBTU to include a safety margin for variations in fuel carbon content.

VII. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified on Part 1b of the forms in the application and duplicated below were confirmed by the initial operating permit inspection. Records are available that confirm the insignificance of the activities. Appropriate recordkeeping is required for those activities indicated below with an asterisk. HRMT has included some activities that are not present at the refinery but that may be required in the future. For instance, wood chipping is not currently performed but could be required on a temporary basis in the event that a tornado destroyed large numbers of trees on refinery property.

Space heaters, boilers, process heaters, and emergency flares less than or equal to 5 MMBTUH heat input (commercial natural gas).

Emissions from gas turbines with less than 215 KW rating of electric output.

*Storage tanks with less than or equal to 10,000 gallons capacity that store volatile organic liquids with a true vapor pressure less than or equal to 1.0 psia at maximum storage temperature.

Gasoline, diesel fuel, aircraft fuel, and fuel oil handling facilities, equipment and storage tanks except those subject to NSPS and standards in OAC 252:100-37-15, 39-30, 39-41, and 39-48, or with a capacity greater than 400 gallons.

*Emissions from storage tanks constructed with a capacity less than 39,894 gallons that store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature.

Additions or upgrades of instrumentation or control systems that result in emissions increases less than the pollutant quantities specified in OAC 252:100-8-3(e)(1).

Welding and soldering operations utilizing less than 100 pounds of solder and 53 tons per year of electrodes. Any welding or soldering is for maintenance purposes only, and is thus a Trivial activity.

Wood chipping operations not associated with the primary process operation.

Torch cutting and welding of under 200,000 tons of steel fabricated. Any such activity is for maintenance purposes only, and is thus a Trivial activity.

Site restoration and/or bioremediation activities of less than 5 years duration.

Hydrocarbon contaminated soil aeration pads utilized for soils excavated at the facility only.

Emissions from the operation of groundwater remediation wells including but not limited to emissions from venting, pumping, and collecting activities subject to *de minimis* limits for air toxics (OAC 252:100-42) and HAP (§112(b) of CAAA '90).

*Non-commercial water washing operations (less than 2,250 barrels per year) and drum crushing operations of empty barrels less than or equal to 55 gallons with less than three percent by volume of residual material.

Hazardous waste and hazardous materials drum staging areas.

Sanitary sewage collection and treatment facilities other than incinerators and POTW. Stacks or vents for sanitary sewer plumbing traps are also included (i.e., lift station).

Emissions from landfills and land farms unless otherwise regulated by an applicable state or federal regulation.

Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas.

The applicant listed numerous activities in its application for the initial TV permit. Some were dismissed as Trivial and some could not be Insignificant because they were subject to various rules and regulations. The non-trivial activities are listed below, but with descriptions of their applicability that are much shorter than that given in the initial Memorandum. Headings are repeated as offered in the original application.

Laboratory

Applicant estimates emission of VOC from laboratory vent hoods to be well below 5 TPY.

Maintenance: Equipment and Piping

Maintenance of lines, pipes, and valves with the emission of VOC may be considered Insignificant only if the VOC emissions result from external cleaning or coating of the equipment. Maintenance associated in any way with the LDAR program is a regulated activity and cannot be Insignificant.

Maintenance: Miscellaneous

Parts cleaning with the emission of VOC. Appendix I allows "Hand wiping and spraying of solvents from containers with less than 1 liter capacity used for spot cleaning and/or degreasing in ozone attainment areas" as an Insignificant activity. OAC 252:100-39-42 controls the design and operation of both cold (§a) and vapor (§b and §c) degreasers in Tulsa County. Further, degreasers may be subject to NESHAP MACT Subpart T. Degreasers affected by these state or federal requirements cannot be considered Insignificant activities.

Operations: Miscellaneous

Backup fuel fired pumps, compressors, or other machines with the emission of SO_x, NO_x, CO, CO₂, VOC, and particulates. Such equipment is included in Appendix I and may require record-keeping.

The loading, unloading, and screening of catalyst and/or support materials with the emission of particulates. Some catalyst may be toxic, with the potential to cause harm. Therefore, DEQ agrees that this should be included as an Insignificant activity and requires that records be maintained for each such transfer and screening event. Such records shall include the type and amount of material handled, applicant's engineering estimate of losses, and the method of calculation.

SECTION VIII. EVALUATION OF AIR QUALITY IMPACTS AND DETERMINATION OF MONITORING REQUIREMENTS**Model Selection and Description**

The PSD modeling was conducted in accordance with the modeling protocol dated April 22, 2013, and reviewed by AQD, and the subsequent draft *Request to use Tier 3 Plume Volume Molar Ratio Method and/or Ozone Limiting Method for NO₂ Modeling* (draft March 12, 2014, updated May 19, 2014) which was also submitted to the EPA. Modeling was completed following the *Guideline on Air Quality Models* 40 CFR Part Appendix W and the *AQD Modeling Guidelines*, with additional guidance from AQD staff.

Criteria pollutant modeling was conducted using Lakes Environmental Software, AERMOD View (Version 8.7). This software incorporates the AMS/EPA Regulatory Model (AERMOD) Version 14134, endorsed by EPA. AERMOD is a regulatory steady state plume modeling system. Five years of hourly meteorological data from the state Mesonet site in Bixby, Oklahoma (2006 – 2010) were input into the model. In accordance with AQD modeling guideline Section C.5.d., the EPA-approved AERMOD Model Version 14134 was used for Class II modeling, and for Class I significance modeling at 50 km distance. Other models were used as required to complete modeling analyses. CALPUFF Version 5.2.0 was used for Tier 2 significance modeling. The VISCREEN visibility model Version 13190 was used for Class II visibility screening.

Class II Area Dispersion Modeling Approach by Pollutant

Class II area modeling was completed to assess project impacts, including the significance analysis, the PSD NAAQS and increment consumption analyses. This section presents the modeling approach by each pollutant considered.

NO₂ Modeling Approach

A full impact modeling analysis was required for 1-hour and annual average NO₂ emissions. SIL, NAAQS, and increment modeling for the project and nearby sources was completed using Tier 3 methods utilizing OLM group ALL for a combined plume analysis. Background concentration data was added for the NAAQS modeling.

EPA provides NO₂ modeling guidance in two memoranda, *Guidance Concerning the Implementation of the 1-hour NAAQS for the Prevention of Significant Deterioration Program* (EPA 2010a) and *Additional Clarification Regarding the Application of Appendix W Modeling Guidance for the 1-hour NO₂ National Ambient Air Quality Standard* (EPA 2011), as well as 40 CFR Part 51 Appendix W (EPA 2005). The guidance lists three refinement Tiers for completing 1-hour NO₂ modeling to obtain design concentrations for the short-term standard, the five-year average of the 98th percentile of the annual distribution of daily maximum 1-hour NO₂ concentrations, and also for the maximum annual average NO₂ concentrations over the numbers of years modeled. Tier 1 assumes full conversion of in-stack nitric oxide (NO) emissions to NO₂. Tier 2 applies a default ambient conversion ratio of 0.90 for NO-to-NO₂ conversion. The Tier 3 method is to further refine the modeling analysis and conversion of in-stack NO to ambient NO₂ using the Plume Volume Molar Ratio Method (PVMRM) or the Ozone Limiting Method (OLM), with five years of hourly background ozone data that are concurrent with the meteorological data set. For Tier 3, an initial in-stack conversion of NO to NO₂ is assumed as a ratio to total NO_x emissions (or an in-stack NO₂/NO_x ratio).

Use of a Tier 3 analysis requires approval from AQD and submittal of a protocol to EPA for approval. Comments received by EPA on the Tier 3 modeling protocol will be addressed separately in a final response to EPA.

AQD provided the 98th percentile hourly NO₂ and ozone concentration files for 2006-2010, processed on a Seasonal, Hour-of-Day and Day-of-Week basis from the North Tulsa monitor (40-143-1127). For HRMT sources, the EPA default in-stack NO₂/NO_x ratio of 0.5 was used. For nearby facilities, the agency has provided in-stack ratios for various types of combustion sources. AQD has based the in-stack NO₂/NO_x ratios for engines, and heaters/boilers on test data for similar sources. The EPA default in-stack NO₂/NO_x ratio of 0.2 was used for all other nearby sources. Tier 3 modeling was completed using the default equilibrium ratio of 0.9.

In-Stack NO₂/NO_x Ratios for Nearby Sources

Source Type	Ratio
LB Engines	0.35
4SRB Engines	0.05
Boilers	0.10
Other Emission Units	0.20

For NO₂, there is a specific control option in AERMOD referred to as the “EPA NAAQS Option,” which was used for modeling NO₂ NAAQS compliance. This option is effective for calculating impacts from 1-hour NO₂ as they relate to EPA regulations. A use of this Method applied to this modeling study is the contribution or “MAXDCONT” output files that display source group contributions to concentration totals at individual receptors, paired in time and space, and allowing a cause and contribute analysis to be performed.

PM₁₀ and PM_{2.5} Modeling Approach

A full impact modeling analysis was required for 24-hour PM₁₀ and PM_{2.5} emissions. SIL, NAAQS, and increment modeling for the project and nearby emission sources was completed following EPA and AQD guidance for these pollutants. Background concentration data was added for the NAAQS modeling analysis. EPA provides PM_{2.5} modeling guidance in *Modeling Procedures for Demonstrating Compliance with the PM_{2.5} NAAQS* (EPA 2010b).

AERMOD has a specific control option in AERMOD referred to as the “PM_{2.5} EPA NAAQS Option,” which was used for modeling PM_{2.5} NAAQS compliance. This option is effective for calculating impacts from 24-hour PM_{2.5}, as they relate to EPA regulations. A use of this method applied to this modeling study is the contribution or “MAXDCONT” output files that display source group contributions to concentration totals at individual receptors, paired in time and space, and allowing a cause and contribute analysis to be performed.

For annual project PM₁₀ and PM_{2.5} emissions, only a significance analysis was completed. A full impact analysis was not required. Due to expected NAAQS modeling impact exceedances from nearby regional sources (not due to HRMT and HEP sources), HRMT and HEP opted to show compliance with the SIL.

On May 20, 2014, EPA released the final document entitled *Guidance for PM_{2.5} Permit Modeling* (EPA 2014) that provides procedures for addressing direct and secondarily formed PM_{2.5} impacts. The guidance defines the significance emissions rate (SER) for direct PM_{2.5} impact analysis as 10 TPY, and the SER for the PM_{2.5} precursors NO_x and/or SO_x as 40 TPY. With this new guidance, a Case 3 PM_{2.5} modeling impact analysis would need to be completed if the NO_x net emission increase exceeds the SER.

As required by Consent Decree, HRMT West recently completed facility changes with large actual SO_x and NO_x emission reductions. The emission reductions, while mandated for SO₂ and NO_x, are contemporaneous and creditable with the proposed project for secondary PM_{2.5} impacts. Actual SO_x emissions will decrease 1,918 tons/year, based upon the difference between reported 2010-2011 SO_x emissions (2,300 tons/year) and the Projected Actual Emissions (PAE) for SO_x (382 tons/year) after project completion. Actual NO_x emissions will increase 584 tons/year, based upon the difference between reported 2010-2011 NO_x emissions (1,036 tons/year) and the Projected Actual Emissions for NO_x (1,620 tons/year) after project completion. Therefore, overall there will be a large net decrease of combined SO_x and NO_x emissions of 1,334 tons/year. Note that

standard EPA interpollutant ratios value SO_x emission reductions at 2-5 times NO_x emission reductions. No further analysis of secondary PM_{2.5} impacts should be required.

CO Modeling Approach

For 1-hour and 8-hour average, project CO emissions, only a significance analysis was completed. Full impact modeling was not required because modeled impacts were below the SILs.

Control Parameters

AERMOD was run in the regulatory default mode, including stack-tip downwash and use of elevated terrain algorithms. The exception was use of the non-regulatory default Tier 3 OLM option for NO₂ modeling.

The land type in the area must be classified as either urban or rural so that appropriate dispersion parameters may be used with AERMOD. The area within and surrounding the refineries is industrial, and the facility is located in a metropolitan area. To simulate the urban heat island effect, the urban option within AERMOD was selected, assuming the Tulsa population equals 396,466 persons, and with a surface roughness of 1.0 meter.

AERMOD has the capability to account for building downwash produced by airflow over and around structures. Direction-specific building downwash parameters were developed for HRMT sources for input to AERMOD-PRIME using the USEPA Building Profile Input Program, or BPIP-PRIME Model (Version 04274). The BPIP model requires building dimensions as well as stack locations for input. These parameters were determined from site plan maps.

Terrain Considerations

Per AQD guidance, modeling with elevated terrain was conducted. AERMAP (version 11103), was used to assign elevations to stack, buildings, receptors, and hills. Receptor elevations were developed using the National Elevation Dataset (NED) data. The NED data was converted to GeoTIFF format and processed using the Lakes Environmental AERMOD View GUI interface with AERMAP. NED data was processed at 1/3 Arc-Sec resolution; receptor terrain values were interpolated from the nearest NED grid points. Elevations were manually applied to sources and buildings using Google Earth. In the case of where results were sensitive to the elevations at design receptors, interpolated elevations were visually verified using topographical maps and Google Earth, and then refined as needed for accuracy. The base elevation of the facility is approximately 640 feet above mean sea level.

USEPA guidance supports the use of AERSURFACE to process land cover data to determine the surface characteristics (i.e., surface roughness, Bowen ratio, and albedo) for the meteorological measurement site that is used to represent meteorological site conditions. Chapter 2.3.4 of AQD's *Air Dispersion Modeling Guidelines for Oklahoma Air Quality Permits* also indicates that surface characteristics using AERSURFACE can be used for air permit applications. The GeoTIFF file for Oklahoma containing the land cover data is used as input for AERSURFACE. AQD's modeling guidance document also recommends the following input conditions for running AERSURFACE:

- Center the land cover analysis on the meteorological measurement site.
- Analyze surface roughness within 1 km of measurement site.
- Utilize one sector determining the surface roughness length.
- Temporal resolution of the surface characteristics should be determined on a monthly basis.
- The region does not experience continuous snow cover for most of the winter.
- The Mesonet site is not considered an airport.
- The region is not considered an arid region.
- Utilize the default season assignment (winter=Dec, Jan, Feb; Spring=Mar, Apr, May; Summer=Jun, Jul, Aug; Fall=Sep, Oct, Nov)

Background Concentrations

For the PSD NAAQS analysis, background concentration data was added to impacts from the proposed project and regional sources. AQD provided representative data for NO₂, PM_{2.5}, and PM₁₀.

The maximum background concentrations are from the North Tulsa monitoring station 40-143-1127. Values are listed in the table following. For short-term standards, the conservative approach was to add the maximum background concentrations to the NAAQS modeling results. Due to the form of the NO₂ short-term standard, EPA provides other options as detailed in the June 2011 memorandum (EPA 2011). The monitor is located approximately 10 km north of the Holly East Refinery and Holly West Refinery. Other nearby facilities in Tulsa including Empire, Covanta, PSO Tulsa, Veolia Energy and Aeon are similarly situated. The winds mainly blow from a southwesterly to southeasterly direction and the aforementioned facilities impact the monitor when the wind blows from that direction. Therefore, full impact modeling when taking into account background concentrations will have the potential for double-counting impacts from those facilities. Because the monitor is located on the north side of the Tulsa metropolitan statistical area, it closely represents the metropolitan area and industrial presence in the Tulsa area.

Background Concentration Data

Pollutant	Basis	Period of Record	Background Concentration
NO ₂	1-hour average daily maximum concentration (98 th percentile) averaged over 3 years	2011 – 2013	40.5 ppb (76.2 ug/m ³)
	Maximum annual average	2013	7.87 ppb (14.8 ug/m ³)
PM _{2.5}	24-hour average concentration (98 th percentile) averaged over 3 years	2011 – 2013	21.7 ug/m ³
	Three-year annual average concentration	2011 – 2013	10.0 ug/m ³
PM ₁₀	High-fourth-high (H4H) 24-hour average concentration	2011 – 2013	67.0 ug/m ³
CO	High-second-high (H2H) 1-hour average concentration	2013	1.60 ppm (1,832 ug/m ³)
	High-second-high (H2H) 8-hour average concentration	2013	1.00 ppm (1,145 ug/m ³)

For further NO₂ modeling refinement, rather than use a single monitored background value, 1-hour average ozone and NO₂ background concentration data from the Tulsa monitor, on an hour-by-hour basis, were used in the model to address the spatial and temporal nature of cumulative NO₂ impacts. These hourly concentration files were provided by AQD.

Good Engineering Practice and Building Downwash Evaluation

The dispersion of a plume can be affected by nearby structures when the stack is short enough to allow the plume to be significantly influenced by surrounding building turbulence. This phenomenon, known as structure-induced downwash, generally results in higher model-predicted ground-level concentrations in the vicinity of the influencing structure. Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements outlined in OAC 252:100-8-1.5. GEP stack height is defined as the greater of 65 meters or a height established by applying the formula $H_g = H + 1.5L$, where:

H_g = GEP stack height,

H = height of nearby structures, and

L = lesser dimension (height or projected width) of nearby structures,

or by a height demonstrated by a fluid model or a field study that ensures that emissions from a stack do not result in excessive concentrations of any pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, nearby structures, or nearby terrain features.

The model utilizes the EPA Building Profile Input Parameters (BPIP) program with the plume rise model enhancements (PRM). BPIP-PRIME determines the effect of building downwash on each plume in calculation of maximum impacts.

Meteorology and Surface Characteristics

AQD supplied five years of AERMET (Version 14134) pre-processed meteorological data (2006-2010) from the state Mesonet site in Bixby, Oklahoma. The Bixby site is located about 20.5 km south-southeast from the HRMT East Refinery and about 23 km south-southeast from the HRMT West Refinery. Depending on the design value modeled, either a single 5-year hourly sequential meteorological data set or five single-year hourly sequential meteorological data sets were utilized.

When using AERMET to prepare the meteorological data for AERMOD, the surface characteristics (Albedo, Bowen Ratio, and Surface Roughness Length) for the primary (MESONET) and secondary (NCDC-ISD) meteorological sites were determined using AERSURFACE.

Class I screening by AERMOD modeling uses the same hourly sequential meteorological data set utilized in Class II modeling as described above. Screening by CALPUFF modeling uses the meteorological data set described below.

An option within CALPUFF is to use an ISCST3 meteorological (MET) data file generated with the preprocessor PCRAMMET. For this study, three years of ISCST3-type meteorological data were used in a ‘screening’ version of CALPUFF. RAMMET View 8.1.0 was used to combine three years of surface and upper air ISCST3 MET data. The data were downloaded from the WebMET website.

Default Site Parameters Modeled In CALPUFF

Parameter	Value
Anemometer Height [m]	6.1
Minimum Monin-Obukhov Length [m]	100.0
Surface Roughness Length (Measurement Site) [m]	1.0
Surface Roughness Length (Application Site) [m]	1.0
Noon-Time Albedo	0.2075
Bowen Ratio	1.625
Anthropogenic Heat Flux [W/m ²]	19.0
Fraction of Net Radiation Absorbed at the Ground	0.27

The surface station at the Oklahoma City Will Rogers World Airport was selected and three years from 1986-1988 were used to compile the CALPUFF ready MET files. The closer MET station in Tulsa was not selected because the corresponding upper air data were not available. Due to the distances involved with the CALPUFF modeling, the surface wind data at Oklahoma City are considered representative of conditions near Tulsa. The anemometer height for this station is equal to 6.1 meters. Other site parameters were automatically selected after choosing “urban” as the land use type. The CALPUFF ready output files were generated assuming no precipitation. This file was then imported into CALPUFF.

Receptor Grid

Class II

A Cartesian receptor grid was developed for Class II air dispersion modeling. The Cartesian receptor grid was defined using UTM NAD83 Zone 15. The receptor grids were designed to capture the maximum pollutant impact locations. Following AQD modeling guidance, a receptor grid was placed with spacing of 100 m out to 1 km, 250 m out to 2.5 km, 500 m out to 5 km, 750 m out to 7.5 km, and 1 km out to the edge of the modeling domain. The edge of the modeling domain was determined to be approximately 20 km from the facility for NO₂, and approximately 12 km from the facility for PM₁₀, PM_{2.5} and CO. Discrete property line receptors were spaced no further than 100 meters apart.

Class I

The Tier I significance modeling for Class I areas in AERMOD utilized a Polar receptor grid comprised of a circle of receptors with a 50 km radius. There were a total of 360 receptors, spaced along each degree of the circle. The center point of the grid was located at UTM NAD83 Zone 15, coordinates 228430, 4002440. The polar grid was then converted to a series of discrete Cartesian receptors. Only the receptors within the Class I directional ranges were used to determine maximum Class I impacts for the analyses.

For the CALPUFF model, the recommended method of adding ring receptors was not used. Instead, discrete receptors from the four (4) Class I areas were obtained from AQD and imported into the CALPUFF model. Gridded receptors were not included.

Source Input Parameters

The following table lists the facility source parameters used as AERMOD model inputs. The modeling analysis includes emissions from combustion sources including boilers, heaters, gas engines, and flares. Each stack was modeled as a point source. The AERMOD source parameters for modeling include source coordinates in UTM NAD83, base elevation above MSL, stack height, stack gas exit velocity, stack diameter, and stack gas temperature.

HRMT has considered either the option of installing a new hydrogen plant at West Refinery with shutdown of most of the No 2 Platformer heaters, or an option to retain the No 2 Platformer. In the PSD Modeling Study, the impacts of only the hydrogen plant scenario is presented, including retaining Plat heaters 3 & 4.

Existing gas engines are a special case in terms of modeling. All are considered “not affected” in terms of the project, but the PDA Compressor, H₂ Recycle Compressor, #2 CT Circ Pump Engine, #3 CT Circ Pump Engine, and #6 CT Circ Pump Engine have been electrified and will have contemporaneous emission reductions with the project. Credit for these emission reductions was only used in the PM₁₀ and PM_{2.5} increment modeling analyses. In the new hydrogen plant case, shutdown of No 2 Platformer heaters 1/2, and 5-7 will provide additional emission reductions. Credit for these emission reductions was only used in the PM₁₀ and PM_{2.5} increment modeling analyses.

Each type of modeling impact analysis (SIL, NAAQS, increment) utilized a different set of project emissions rates, calculated in units of gram per second (g/s). For the SIL analysis, Project emissions increases were modeled as the difference between the potential-to-emit (PTE) and the baseline actual emissions (BAE), for each pollutant. For the NAAQS analysis, the Project PTE, regional source PTE, and background concentration data were included. For the increment analysis, Project PTE and regional source PTE from sources installed after the PSD major and minor baseline dates were included. Short-term emission rates were used for each pollutant with 1-hour, 3-hour, 8-hour, or 24-hour averaging time standards, as applicable. Annual emissions rates were used for each pollutant with annual averaging time standards.

The SIL analyses required only the modeling of project emission increases, determined by calculating the difference between the 2010-2011 baseline emission rates and the proposed PTE of each affected or modified emission unit. New units constructed for the project have zero baseline emission rates and are modeled with emission increases up to full PTE. Units constructed within 24 months prior to project operation, are assumed have zero project emission increases, with baseline emissions equivalent to PTE. For example, this situation would apply to Boiler 10 at the West Refinery. In AERMOD, project emission increases are typically denoted by "P" at the end of the AERMOD source ID.

The NAAQS analysis required the modeling of PTE, or the maximum amount of an air contaminant that can be emitted by a source. For an existing modified or affected source, the PTE is the sum of the baseline emission rates and the project emission increases. To reduce the number of modeling files and iterations required in AERMOD, each existing emission source was duplicated and co-located to differentiate between the "baseline" emissions for the source, typically denoted by "B" at the of the AERMOD source ID and the project emissions increase from the source, denoted by the "P" at the end of the AERMOD source ID. This separation also serves the purpose of incorporating project emission increases into the full impact analysis to determine that the project does not cause nor contribute to any potential NAAQS exceedance. This allows SIL, NAAQS, and PSD increment to be modeled together in separate source groupings to streamline the modeling work

Analysis was performed on facility and selected nearby regional sources to determine which units were installed before the major and minor source baseline dates. Emissions permitted before the baseline dates were not included in the PSD increment analysis.

HRMT East Refinery & HEP Modeling Source Parameters

	UTM Coordinate		Base Elevation (m)	Final Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (°K)
	Easting (m)	Northing (m)					
Project Units - New							
CCR Helper Heater (new)	229947	4000693	193	22.9	0.76	9.53	478
NHDS Helper Heater (new)	229670	4000663	192	22.9	0.46	10.59	478
DHTU Helper Heater (new)	229945	4000602	195	22.9	1.00	11.07	478
ROSE Heater (new)	229928	4000641	195	22.9	1.00	9.30	478
Project Units - Affected or Modified							
DHTU Charge Heater 1H-101	229947	4000617	195	42.7	1.46	6.95	583
CCR Charge Heater 10H-101, #2-1 Interheater 10H-102, #2-2 Interheater 10H-103	229950	4000673	195	37.8	1.77	19.86	561
CCR Stabilizer Reboiler 10H-104 & Naphtha Splitter Reboiler	229951	4000700	195	37.8	1.37	21.00	533
CCR Interheater #1 10H-113	229971	4000688	195	38.1	2.53	5.24	466
Boiler #1	229910	4001435	193	18.2	1.83	13.63	422
Boiler #2	229918	4001435	193	18.2	1.83	13.63	422

	UTM Coordinate		Base Elevation (m)	Final Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (°K)
	Easting (m)	Northing (m)					
Boiler #3	229936	4001434	193	18.2	1.83	13.63	422
Boiler #4	229945	4001434	193	18.2	1.83	13.63	422
Sulfur Recovery Unit/Tail Gas Treating Unit (SRU/TGTU) #1	229823	4000611	192	61.0	0.61	5.88	501
Sulfur Recovery Unit/Tail Gas Treating Unit (SRU/TGTU) #2	229762	4000608	192	30.8	0.76	7.65	341
NHDS Charge Heater 02H-001	229664	4000659	192	30.5	1.13	9.84	693
NHDS Stripper Reboiler 02H-002	229658	4000653	192	29.3	1.13	12.74	791
Vacuum Tower Heater	229956	4001097	194	53.3	3.51	1.60	450
CDU Atmospheric Tower Heater	229956	4001088	194	30.5	3.0	5.42	450
FCCU Charge Heater B-2	229945	4000871	194	46.0	1.77	14.41	625
FCCU Regenerator	229945	4000861	194	46.0	1.52	15.52	333
Unifiner Charge Heater H-1	229938	4000775	193	14.6	1.16	10.72	783
Scanfiner Charge Heater 12H-101	229954	4001001	193	13.7	1.07	7.95	585
VCU Terminal Loading	229352	4000605	193	13.7	2.44	3.08	1,033

HRMT West Refinery Modeling Source Parameters

	UTM Coordinate		Base Elevation (m)	Final Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (°K)
	Easting (m)	Northing (m)					
Project Units - New							
Modified PDA to ROSE, new heater	228750	4003806	195.1	22.9	1.00	16.83	478
Hydrogen Plant Reformer Heater	228143	4004066	195.0	22.9	1.52	13.30	533
Project Units - Affected or Modified							
#7 Boiler	228660	4003895	195.1	18.3	1.52	12.13	430
#8 Boiler	228660	4003903	195.1	18.3	1.52	13.57	481
#9 Boiler	228658	4003859	195.1	24.4	1.52	11.37	403
#10 Boiler	228588	4003843	195.1	15.2	1.45	21.83	459
CDU Atmospheric Tower Heater - North Stack	228262	4003837	194.3	41.2	2.26	7.17	522
CDU Atmospheric Tower Heater - South Stack	228261	4003822	194.3	41.2	2.26	7.11	518
CDU #1 & #2 Vacuum Tower Heaters	228279	4003823	194.5	38.1	2.26	7.59	718
EG-5747	228750	4003806	195.1	6.71	0.15	13.20	589
Unifiner Charge Heater	228239	4003969	194.6	20.1	1.37	4.89	574

	UTM Coordinate		Base Elevation (m)	Final Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (°K)
	Easting (m)	Northing (m)					
Unifiner Stripper Reboiler Heater	228239	4003982	194.3	23.5	1.52	5.84	522
C-2719	228288	4003961	194.5	7.62	0.21	7.26	547
No. 2 Platformer Charge Heater (PH-1/2)	228247	4004021	193.9	27.7	2.13	7.36	884
No. 2 Platformer Charge Heater (PH-3)	228238	4003989	194.2	15.2	1.37	5.67	673
No. 2 Platformer Charge Heater (PH-4)	228237	4003995	194.2	15.2	1.52	3.83	455
No. 2 Platformer Charge Heater (PH-5)	228262	4004030	193.9	27.4	2.13	4.59	732
No. 2 Platformer Charge Heater (PH-6)	228251	4004029	193.9	25.9	1.52	5.06	769
No. 2 Platformer Charge Heater (PH-7)	228246	4004013	193.9	30.8	1.13	9.13	1,039
Coker Drum Charge Heater (B-1)	228528	4004114	195.1	34.1	1.68	5.79	621
Coker Preheater (H-3)	228524	4004106	195.4	27.7	1.22	5.26	555
LEU Raffinate Mix Heater (H101)	229176	4003722	195.1	27.4	0.91	6.36	543
LEU Extract Mix Heater (H102) North Stack	229185	4003728	195.1	38.1	1.62	5.98	558
LEU Extract Mix Heater (H102) South Stack	229185	4003718	195.2	38.1	1.62	6.03	563
LEU Hydrotreater Charge Heater (H201)	229176	4003712	195.1	30.5	1.62	2.32	619

	UTM Coordinate		Base Elevation (m)	Final Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (°K)
	Easting (m)	Northing (m)					
MEK - Wax Free Oil Heater	229194	4003727	195.2	34.1	1.83	5.06	478
MEK - Soft Wax Heater (H-2)	229202	4003723	195.2	19.0	1.07	9.08	483
EG-5579	228851	4003794	195.0	7.62	0.31	2.65	616
EG-5156	228578	4004020	195.0	7.62	0.31	0.001	644
EG-5152	228605	4003885	195.0	5.49	0.31	0.001	616
EG-5154	228617	4003889	195.0	5.49	0.15	14.33	616

HRMT emissions permitted before the applicable major source baseline dates were excluded from increment analyses. In addition to the new sources for this project, the following sources were included in the increment review

	NO ₂	PM ₁₀	PM _{2.5}
HRMT East Refinery			
Naphtha Splitter Reboiler	+2011	+2011	
CCR Interheater #1 (10H-113)	+2005	+2005	
Sulfur Recovery Unit (SRU) #2	+2006	+2006	
NHDS Charge Heater	+2006	+2006	
NHDS Reboiler Heater	+2006	+2006	
Scanfiner Charge Heater	+2004	+2004	
CDU Atmospheric Tower Heater			
HEP			
Loading racks / VCU	+2012	+2012	
HRMT West Refinery			
#3 Boiler	-2014	-2014	-2014
#4 Boiler	-2014	-2014	-2014
#10 Boiler	+2014	+2014	+2014
PDA Propane Compressor	-2013	-2013	-2013
Unifiner H2 Recycle Compressor	-2013	-2013	-2013
No. 2 Platformer Charge Heater (PH-4)	+2014	+2014	+2014
No. 2 Platformer Charge Heater (PH-5)	+1990	+1990	
Coker Drum Charge Heater (B-1)	+1992	+1992	
Coker Preheater (H-3)	+1995	+1995	
#2 CT Circ Pump Engine	-2013	-2013	-2013
#3 CT Circ Pump Engine	-2014	-2014	-2014
#6 CT Circ Pump Engine	-2014	-2014	-2014
#6 CT Spray Pump Engine	-2013	-2013	-2013

Reductions in actual emissions are credited for shutdown sources. Only the proposed new sources and associated emission increases at existing sources are included in the increment analysis for PM_{2.5}.

Regional sources excluded from increment analysis include PSO Tulsa, Empire Castings, and all but the most recently permitted turbine at Veolia (permitted 2007). Increment analysis must identify impacts of actual emissions, but for screening the higher potential emissions were used except where actual operating data was provided by AQD.

Urban/Rural Classification

Section 8.2.3 of the GAQM provides the basis for determining the urban/rural status of a source. For most applications, the land use procedure described in Section 8.2.3(c) is sufficient for determining the urban/rural status. However, there may be sources located within an urban area, but located close enough to a body of water to result in a predominantly rural classification. In those cases, the population density procedure may be more appropriate. Only the following land use procedure is used to assess the urban/rural status of the source.

- Classify the land use within the total area, A_o , circumscribed by a 3-km radius circle about the source using the meteorological land use typing scheme proposed by Auer.
- If land use Types I1 (heavy industrial), I2 (light-moderate industrial), C1 (commercial), R2 (single-family compact residential), and R3 (multifamily compact residential) account for 50 percent or more of A_o , use urban dispersion coefficients; otherwise, use appropriate rural dispersion coefficients.

Based on visual inspection of the USGS 7.5-minute topographic map of the project site location, it was conservatively concluded that over 50 percent of the area surrounding the project may be classified as urban. Accordingly, the urban dispersion modeling option is used in the AERMOD PRIME model.

Regional Inventory Emissions and Source Parameters

AQD provided an inventory of source parameters and emission rates for each pollutant for nearby sources in the Tulsa region. Stack locations, source parameters and emission rates were provided for modeling. The stack location coordinates were independently researched for inconsistencies with the site address prior to use in the modeling. Where information differed from the AQD database, corrections were entered to the inventory. Google Earth was used to corroborate or correct regional source facility coordinates provided in the ARIES file.

All regional sources within 10 km were included in the analysis while all regional sources outside of 50 km were excluded from the analysis. The AQD narrowed the list of existing nearby sources required to be included in the NAAQS and increment modeling analyses to only those that would be expected to have a significant concentration gradient within the modeling domain for those sources outside of 10 km, but within 50 km. The facility eliminated two sources from the list provided by AQD using the “10 D Rule,” which eliminates sources from the modeling review when the emissions (TPY) are less than 10 times the distance (in kilometers) from the modeled facility: “BIZJET INTL” and “ST FRANCIS HOSP”.

Regional sources are only included in the Class II full impact modeling analyses. The regional source emission rates are permitted, potential-to-emit values for short-term modeled rates, unless otherwise noted. AQD provided operating factors for some units to be used on annual emission rates. The operating factors account for the assumption that equipment does not operate 8,760 hours per year. With AQD approval, some units were allowed to be “excluded as intermittent” from 1-hr short-term impacts in the modeling study.

Significance Analysis

Dispersion modeling analysis usually involves two distinct phases; a preliminary analysis and a full impact analysis. The preliminary analysis models only the significant increase in potential emissions of a pollutant from a proposed new source, or the significant net emissions increase of a pollutant from a proposed modification. The results of this preliminary analysis determine whether the applicant must perform a full impact analysis, involving the estimation of background pollutant concentrations resulting from existing sources and growth associated with the proposed project. Specifically, the preliminary analysis:

- determines whether the applicant can forego further air quality analyses for a particular pollutant;
- may allow the applicant to be exempted from the ambient monitoring data requirements; and
- is used to define the impact area within which a full impact analysis must be carried out.

In general, the full impact analysis is used to project ambient pollutant concentrations against which the applicable NAAQS and PSD increments are compared, and to assess the ambient impact of non-criteria pollutants. The full impact analysis is not required for a particular pollutant when emissions of that pollutant would not increase ambient concentrations by more than the applicable significant impact level (SIL).

For the pollutants that exceeded the SERs, NO₂, PM_{2.5}, PM₁₀ and CO, preliminary modeling was completed for comparison to the SIL. For pollutants with maximum off-site ambient concentrations less than the applicable SIL, no further impact assessment is required. If impacts are greater than the SIL, then a full impact modeling analysis is required, including a NAAQS modeling analysis (Class II areas) and a PSD increment consumption analysis (Class I and Class II areas). Air quality modeling for ozone impacts is not required because VOC emission increases from the Project will not exceed 100 TPY.

Using EPA's May 2014 "Guidance for PM_{2.5} Permit Modeling," a full impact analysis for PM_{2.5} is not required if: (1) the difference between the PM_{2.5} background concentration and the PM_{2.5} NAAQS is greater than the PM_{2.5} significance impact level; and (2) the modeled impacts of PM_{2.5} from the project would not increase ambient concentrations by more than the PM_{2.5} significant impact level (SIL). The same analysis was completed for NO₂, CO and PM₁₀. As demonstrated by the following table, a full impact analysis is not required for CO or annual PM₁₀.

The full impact analysis considers emissions from existing sources, as well as the emission increases associated with the project, to comply with NAAQS and PSD increment consumption analyses. This required the addition of background concentration levels and regional source emissions, as provided by AQD.

Pollutant	Averaging Period	Max Project Impact $\mu\text{g}/\text{m}^3$	SIL $\mu\text{g}/\text{m}^3$	Full Impact Analysis Required?
NO ₂	1-hr	103	7.5	Yes
	Annual	6.6	1	Yes
PM ₁₀	24-hr	5.5	5	Yes
	Annual	0.7	1	No
PM _{2.5}	24-hr	4.4	1.2	Yes
	Annual	0.6	0.3	Yes
CO	1-hr	210	2,000	No
	8-hr	103	500	No

Full Impact Analyses

The next step was to perform a full impact analysis. The full impact analysis considers emissions from existing sources, as well as the emission increases associated with the project, to comply with NAAQS and increment consumption analyses. A Class II full impact analysis was required for NO₂, PM_{2.5}, and PM₁₀ because the SILs were exceeded. The full impact analysis required more refined modeling to compare impacts to the Class II National Ambient Air Quality Standards (NAAQS). For the NAAQS analysis, modeling results for the combined criteria pollutant impacts from Holly East, Holly West, HEP and regional sources were added to corresponding background concentrations.

Modeling results for NAAQS and Class II increment analyses are presented following. MAXDCONT files were used to assist in demonstrating compliance with the 1-hour NO₂ and PM_{2.5} 24-hour NAAQS. The MAXDCONT files were used to pair impacts in time in space at receptors to demonstrate that project impacts are not significant at the occurrence of a NAAQS or increment exceedance. The results are presented in the corresponding tables following.

Compliance with the NAAQS is demonstrated when: 1) modeled impacts are below the NAAQS standards (for example on the Holly East Refinery and Holly West Refinery property lines) and, 2) modeled impacts from the proposed Project emission increases are not significant at any locations where the NAAQS is exceeded (for example by a regional source).

For purposes of NAAQS compliance, where background concentrations are added to modeled impacts, AQD provided guidance on minimizing double counting due to the nearby facility emission impacts on the background monitoring data. For sources impacting the monitor, modeled emission rates were reduced by a factor representing actual emissions times the source operating factor.

The modeling results for 1-hour and annual NO₂ are presented here. There were 56 predicted violations of the NAAQS confined to eight receptors within the modeling domain out to the Highest 29th High impact. The maximum 1-hour NO₂ NAAQS impacts for the eight receptors, paired with the corresponding project contribution in time and space, is shown in the following table. The project does not contribute a significant impact at the location of maximum NAAQS impact. The annual NO₂ maximum impact did not exceed the NAAQS at any receptor and did not require further analysis.

NO₂ Max NAAQS & Project Contribution NO₂ Max NAAQS & Project Contribution

Pollutant	Averaging Period	NAAQS ug/m ³	Max Impact ug/m ³	E UTM m	N UTM m	Project Contribution ¹ ug/m ³
NO ₂	1-hour	188	217.4	247430	4009440	0.01
			196.0	230330	4005040	1.16
			191.9	230230	4005040	0.02
			191.4	230330	4005140	0.77
			189.4	230230	4005140	0.05
			189.3	230230	4004840	0.03
			188.1	230230	4004940	0.03
			188.1	230430	4005040	0.84
	Annual	100	72			

¹1-hour NAAQS and project contribution paired in time & space using MAXDCONT.

PM₁₀ full impact modeling was performed to demonstrate compliance with the 24-hour NAAQS standard, and the results are in the following table. There is not an annual NAAQS standard for PM₁₀.

PM₁₀ NAAQS Modeling Results

Pollutant	Averaging Period	NAAQS ug/m ³	Impact ug/m ³	NAAQS Exceeded?
PM ₁₀	24-hour	150	125	No

PM_{2.5} full impact modeling was performed to demonstrate compliance with the 24-hour and annual NAAQS standards. There were 403 potential violations of the PM_{2.5} 24-hour NAAQS confined to 12 receptors within the modeling domain. The maximum NAAQS impact, paired with the corresponding project contribution in time and space, for the 12 receptors is presented below. There were 50 potential violations of PM_{2.5} Annual NAAQS. Only the receptor with the highest impact and the receptor with the highest project impacts are shown below. The project was not significant at any of the receptors where a potential violation occurred.

PM_{2.5} Max NAAQS & Project Contribution

Pollutant	Averaging Period	NAAQS ug/m³	Max Impact ug/m³	E UTM m	N UTM m	Project Contribution¹ ug/m³
PM_{2.5}	24-hour	35	60.4	220430	3989440	0.02
			57.5	238430	4004440	0.02
			50.3	220430	3988440	0.10
			42.4	224430	3995440	0.24
			41.7	220430	3990440	0.00
			39.3	236430	4007940	0.09
			38.8	224430	3995940	0.01
			38.7	228030	4005140	0.27
			38.2	220430	3987440	0.02
			37.9	219430	3989440	0.03
			37.6	228030	4005040	0.13
			36.4	222430	4003440	0.04
	Annual	12	19.2	238430	4004440	0.03
			12.2	228530	4002440	0.28

¹1-hour NAAQS and project contribution paired in time & space using MAXDCONT.

For the PM_{2.5} 24-hour NAAQS there was a single receptor where the combined impacts from HRMT East Refinery, HRMT West Refinery, and HEP facilities exceeded the SIL and the PM_{2.5} 24-hour NAAQS. This receptor was within Empire Castings facility was due primarily to emissions from Empire Castings. Approval was granted by AQD to subtract regional source impacts from the total impacts at this receptor within the Empire Casting boundaries to assist with NAAQS compliance. After subtracting the contribution of Empire Castings within the airspace of Empire Castings (per EPA memo "Ambient Air", October 17, 1989), there were no NAAQS exceedances.

Adjusted 24-Hour PM_{2.5} Impact Analysis Within Empire Fencelines¹

Receptor Within Empire Fenceline		NAAQS (µg/m ³)	Modeled Impact (µg/m ³)	Empire Contribution (µg/m ³)	Corrected Impact ¹ (µg/m ³)	NAAQS Exceeded?
X Coord.	Y Coord.					
228030	4005140	35	38.7	15.5	23.2	
228030	4005140	35	37.7	14.0	23.7	NO
228030	4005140	35	37.3	13.2	24.1	NO
228030	4005140	35	37.0	13.0	24.0	NO
228030	4005140	35	36.8	12.8	24.0	NO
228030	4005140	35	36.5	11.9	24.6	NO
228030	4005140	35	36.3	12.7	23.6	NO
228030	4005140	35	35.9	11.7	24.2	NO
228030	4005140	35	35.7	11.9	23.8	NO
228030	4005140	35	35.5	11.6	23.9	NO
228030	4005140	35	35.4	11.4	24.0	NO
228030	4005140	35	35.1	11.0	24.1	NO

¹The 24-hour PM_{2.5} impacts from Empire Castings were subtracted from total impact within the facility's fenceline using source groupings.

There were 15 receptors where the combined impacts from HRMT East Refinery, HRMT West Refinery, and HEP facilities exceeded the SIL and the PM_{2.5} Annual NAAQS. However, since the project impacts were below the SIL no further analysis was conducted.

PSD Increment Consumption

To complete the PSD increment consumption analysis, the criteria pollutant emissions increase above the PSD baseline level for each emission source considered in the study must be modeled. The increments are more stringent for Class I areas such as National Parks and wilderness areas, than for Class II areas, such as the area near the site. A Tier I analysis uses potential emissions, and if compliance is unable to be demonstrated, than a Tier II analysis is used with actual emissions.

Not all emission sources are assumed to be increment-consuming. For each pollutant, the PSD increment analysis includes only the project emission increases for all units built before the applicable major and minor source baseline dates and PTE for all regional sources built after the applicable major and minor source baseline dates.

The major source baseline date for NO₂ is February 8, 1988. The major source baseline date for PM₁₀ is January 1, 1975. The major source baseline date for PM_{2.5} is October 20, 2010. All emission increases and decreases at major sources after the major source baseline dates must be included in the regional increment consumption analysis. The Tulsa County NO₂ minor source baseline date was triggered in Air Quality Control Region (AQCR) 186, including Tulsa County,

on June 23, 1989. The PM₁₀ minor source baseline date was triggered in Tulsa County on September 9, 1982 and the remainder of AQCR 186 on August 25, 1982. Minor source emission changes after the minor source baseline dates must be included in the regional increment consumption analysis. The PM_{2.5} minor source baseline has not been triggered to date, but will be triggered by this PSD application. Therefore, no minor source emission increases or decreases will consume increment for PM_{2.5}.

Compliance with the PSD increment consumption analysis is shown when: 1) total increment consumption after the baseline date does not exceed the increments and 2) impacts from proposed project emission increases are not significant at any locations where the increment thresholds are exceeded (for example by a regional source).

PSD increment modeling results for annual NO₂ increment are presented in the following table. The maximum impact, found in the year 2007, does not exceed the increment, therefore, no further modeling was required.

NO₂ Class II Increment Modeling Results

Pollutant	Averaging Period	Increment ug/m ³	Max Impact ug/m ³	Increment Exceeded?
NO ₂	Annual	25	15.2	No

PSD increment modeling results for 24-hour PM₁₀ increment are presented below. The modeling submitted by the applicant predicted a potential violation of the PM₁₀ 24-hour increment. There were five receptor locations where predicted potential violations of the Increment occurred. The maximum 24-hour PM₁₀ Increment impacts for the five receptors, paired with the maximum impact from the project, are shown in the following table. The project does not have a significant impact (5 µg/m³) at the location of these five receptors.

After reviewing the increment consuming nearby source emissions, it was noted that some of the sources contributing to the potential violation were modeled using PTE rather than actual emissions. Additional modeling conducted by the AQD using actual emissions for the sources contributing to the potential modeled exceedances showed that there were no potential violations of the PM₁₀ 24-hour increment. The PM₁₀ annual PSD increment study was not required because the SIL was not exceeded.

PM₁₀ Increment Results For Year With Maximum & Project Contributions

Pollutant	Averaging Period	Increment µg/m ³	Max Impact µg/m ³	E UTM m	N UTM M	Max Project Contribution µg/m ³
PM ₁₀	24-hour	30	38.9	220430	3988440	0.2
			58.6	220430	3989440	0.2
			42.9	224430	3995440	0.4
			31.6	224430	3995940	0.3
			45.9	238430	4004440	0.3

AQD PM₁₀ Class II Increment Modeling Results

Pollutant	Averaging Period	Increment Threshold ug/m ³	Max Impact ug/m ³	Increment Exceeded?
PM ₁₀	24-hour	30	18.6	No

PSD increment modeling results for 24-hour and annual PM_{2.5} increments are presented below. The increment was not exceeded at any receptor.

PM_{2.5} Class II Increment Modeling Results

Pollutant	Averaging Period	Increment ug/m ³	Max Impact ug/m ³	Increment Exceeded?
PM _{2.5}	24-hour	9	5.5	No
	Annual	4	0.7	No

PSD Monitoring Exemption Thresholds

On a case-by-case basis, AQD has the authority to require pre-construction air quality monitoring for background concentration data, unless modeled impacts from project emission increases, or existing ambient concentrations, are below the PSD monitoring exemption thresholds. Modeling was completed for comparison to the exemption thresholds as shown in the table below. While some of the monitoring exemption thresholds are exceeded by modeled impacts, representative background concentration data are available from the North Tulsa monitor (40-143-1127). Therefore, pre-construction monitoring is not needed.

Pollutant	Averaging Period	Monitoring Exemption Threshold ug/m ³	Maximum Impacts ug/m ³	Threshold Exceeded?
NO ₂	Annual	14	6.6	No
PM ₁₀	24-hour	10	5.3	No
CO	8-hour	575	103	No

Ozone Impacts Assessment

Under OAC 252:100-8-35.2(c), an increase in NO_x or VOC of 100 TPY triggers an ambient impact analysis for ozone, including gathering of ambient air quality data. That ambient monitoring is already being performed in the Tulsa metro area, therefore, that requirement is adequately fulfilled.

The calculated NO_x emissions increase of 544 TPY result mostly from increased utilization of existing units. Added NO_x emissions from 376 MMBTUH of additional heaters and one modification of capacity would be 49 TPY. The net increase does not take into account significant reductions in both NO_x and VOC required by the recent facility Consent Decree.

The area will have a rather large decrease in actual NO_x emissions from implementation of Consent Decree requirements. These projects include retirement of Boilers 1 through 4, installation of two flare gas recovery units (FGRU) which decreased the amount of gas being flared, and emissions reductions at the Fluid Catalytic Cracking Unit (FCCU). The reduction in actual emissions from those activities was 1,001 TPY NO_x. While netting analyses do not allow the inclusion of emission reductions achieved through consent decrees, they should be considered in the evaluation of actual changes in ozone impacts for the facility, because impact analyses do not force technology nor require controls but instead inform the community of the likely changes in ambient pollutant concentrations that may result from the facility.

Ozone analyses typically use a relative response approach to impact assessment. A baseline inventory is modeled to provide an initial value. The inventory is then modified to reflect the future projected actual emissions and modeled again. The difference in projected ozone values is added or subtracted from local monitors to provide a rough assessment of ambient ozone impacts. In evaluating projected ambient ozone concentrations, inclusion of the federally contemporaneous reductions that have occurred at the facility is fully consistent with the logic that requires contemporaneous increases and decreases to be considered in project evaluations in the first place. It provides a more accurate depiction of facility-wide impacts over time. In this instance, reductions in NO_x emissions are well in excess of increases.

It is concluded that the proposed expansion will not have a deleterious effect on ambient ozone concentrations in the Tulsa area.

SECTION IX. OTHER PSD ANALYSES

A. Evaluation of Class I Area Impacts

Class I areas are provided special protection under PSD by Air Quality Related Values (AQRVs) defined and enforced by the Federal Land Manager (FLM). The FLM may recommend against issuance of a PSD permit if a source adversely impacts the AQRVs. Potential AQRV impacts are screened per the FLM guidance in *Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report – Revised (2010)* (NPS 2010). For sources located more than 50 km from a Class I area and passing screening under the 10D Rule there is a presumptive No Adverse Impact. Modeling may still be required to demonstrate compliance with EPA Class increment thresholds.

Under the 10D Rule, the equation $Q/D < 10$ is applied, where:

Q is equal to the sum of the emission increases of NO_x and PM₁₀ that result from the proposed project (in TPY).

D is the distance from the source to the Class I Area (in km).

The maximum project emission increases based upon maximum hourly emissions estimates, $\text{NO}_x + \text{PM}_{10} = 707 \text{ TPY}$, were compared to the minimum Class I distance, 230 km. The Q/D value (3.1) does not exceed 10. Therefore, a refined Class I area analysis evaluating impacts to the AQRVs, including deposition and visibility, is not required. Note that this analysis does not account for the large, contemporaneous reductions in actual NO_x and SO_2 emissions that have recently occurred at the HRMT West refinery.

This section addresses the Class I significance modeling analysis required for the PSD Modeling Study. AERMOD and CALPUFF were used to determine compliance with the Class I significance thresholds. EPA requires an analysis for Class I SILs if a facility is within 300 km of a Class I area. This analysis is a tiered analysis to reduce the burden on the applicant. For Tier I, facilities can model potential emission increases out to 50 km from the project using AERMOD. Otherwise, under Tier II, impacts at receptors within the Class I areas must be evaluated using CALPUFF. CALPUFF is the EPA-recommended model for estimating concentrations at distances greater than 50 km.

Location of Class I Areas within 300 Kilometers

The nearest Class I areas within 300 km of the project site are the Caney Creek Wilderness (250 km), the Hercules-Glades Wilderness (280 km), the Upper Buffalo Wilderness (230 km), and the Wichita Mountains Wilderness (280 km). The Class I area details are summarized following.

Class I Areas Within 300 km of HRMT Facilities

Class I Area	State	Distance (km) and Direction From HRMT
Caney Creek	Arkansas	250 km East-Southeast (137° – 140°)
Hercules-Glades Wilderness Area	Missouri	280 km Northeast (77° – 78°)
Upper Buffalo Wilderness Area	Arkansas	230 km East (97° – 99°)
Wichita Mountains Wildlife Refuge	Oklahoma	280 km Southwest (239° – 241°)

The Class I impact analysis requires the modeling of the project's impacts at 50 km to determine if the project's impacts exceed the Class I SILs. The maxima were obtained in the angular direction of the Class I areas. If impacts are less than the SILs, no further analysis is necessary; if they exceed the SILs, CALPUFF modeling is used to determine project impacts.

Model Results for Class I Tier I Significant Impact Analysis

Pollutant	Averaging Period	Significant Impact Level (ug/m³)	Max Class I Impacts (ug/m³)	Exceeded in Direction of Class I Area?
NO ₂	Annual	0.1	0.04	No
PM ₁₀	24-hour	0.3	0.11	No
	Annual	0.2	0.01	No
PM _{2.5}	24-hour	0.07	0.11	YES
	Annual	0.06	0.01	No

For the Class I Area Tier II significance analysis for 24-hour PM_{2.5}, a refined CALPUFF (Version 5.8, Level 070623) model was created to estimate the concentrations of pollutants exceeding the SIL at 50 km from the project site. CALPUFF is the EPA recommended model for estimating concentrations and long distances greater than 50 km. For this analysis, receptors within each Class I area were included in CALPUFF modeling. The *Guide for Applying the EPA Class I Screening Methodology with the CALPUFF Modeling System* (Earth Tech 2001) was followed to complete this work. The guide was created to assist users through the process of creating input files to run the CALPUFF, CALPOST, and POSTUTIL programs to implement the EPA Screening Methodology for Class I areas. This is a screening methodology, because it does not take advantage of the full three-dimensional modeling produced by CALMET. Instead, an ISCST3 single-station meteorological field was used with three years of processed data, and using two-dimensional wind fields.

Sources without applicable emissions were excluded from CALPUFF modeling. The corresponding stack parameters and building downwash were imported from the AERMOD modeling file. There were no area, volume and line source emissions from the proposed project.

The Tier II screening analysis served to verify that concentrations do not exceed SIL thresholds at these locations. As shown by the Class I screening analysis, given the nature of the project and distance of these Class I areas to the project, the need for additional Class I area analysis including an increment analysis and deposition and visibility analyses was not required.

Class I Area Tier II 24-hour PM_{2.5} SIL Modeling Results

Site	UTM Coordinates ¹		Max Impact ug/m ³	Max Impact Angle (degrees)	50% of Class I SIL Threshold ug/m ³	Exceed Threshold?
	Easting (m)	Northing (m)				
Upper Buffalo	464281	3973391	0.011	97	0.035	No
Caney Creek	393154	3810338	0.018	140	0.035	No
Hercules Glade	504841	4056510	0.007	78	0.035	No
Wichita Mountains	530112	3850452	0.008	241	0.035	No

¹Coordinates are in Zone 15, except for Wichita Mountain, which is in Zone 14.

B. Evaluation of Source-Related Impacts on Growth, Soils, Vegetation, and Visibility

Commercial, Residential, and Industrial Growth Analysis

The intent of a growth analysis is to assess air quality impacts due to residential and commercial growth due directly to a proposed modification or new construction. If such activity requires a large new work force, such growth would result due to the influx of families associated with the workforce.

An increase in the workforce will be observed during construction, but the increase in permanent employees is expected to be small. Because the project is located in an urban setting, it is likely that the majority of any construction workers or new permanent employees will be hired locally and that the true number of relocating families will be quite small. In consideration of these issues, it is estimated that air quality impacts associated with growth will be minimal (if detectable at all).

Soils & Vegetation Analyses

The effect of the proposed project emissions on local soils and vegetation were addressed through comparison of modeled impacts to the secondary NAAQS for NO₂, PM_{2.5}, and PM₁₀ shown in the following table. There is no secondary standard for CO. The secondary NAAQS were established to protect general public welfare and the environment. The secondary NAAQS for NO₂, PM_{2.5}, and PM₁₀ are either identical to or less stringent than the primary NAAQS for the same averaging interval.

Accordingly, compliance with primary NAAQS shown earlier in this report, by modeling of either SIL or NAAQS, demonstrates compliance with secondary NAAQS.

Secondary NAAQS Thresholds

Pollutant	Modeling Design Basis	NAAQS Threshold (ug/m³)
NO ₂	Maximum annual average over each of 5 years modeled	100 (53 ppb)
PM _{2.5}	24-hour average concentration 98 th percentile average at each receptor over 5 years modeled	35
	Annual average, averaged over 5 years	15
PM ₁₀	24-hour average concentration high-6 th high (H6H) at each receptor over 5 years modeled	150

In general, modeled impacts below the secondary NAAQS indicate no adverse impacts on soils and vegetation. No sensitive aspects of the soil and vegetation in this area have been identified. Since modeling results demonstrate compliance with secondary standards it is anticipated that the potential impacts to the soil and vegetation will be negligible.

Based upon the results, it is concluded that the construction of the proposed project will not have a significant adverse impact on the surrounding soil and vegetation.

Visibility Impairment Analysis

The Class II visibility analysis requirements and results are presented in this section. Class II visibility impacts from the project were assessed with the VISCREEN model. AQD guidance was used in conjunction with EPA's *Workbook for Plume Visual Impact Screening and Analysis* (EPA 1992) to assess visibility impacts. Figure 9 from EPA's *Workbook* demonstrates that the background visual range to be used in the modeling for Tulsa, Oklahoma is 40 km.

AQD's guidance for determining visibility impacts in a Class II area allows the screening levels to be three times the Class I screening levels. This means that the relative sensitivity, ΔE , value of 6.0 and an absolute green contrast value of 0.15 were used.

A range of source-observer distances was evaluated, and the results were compared to the appropriate screening thresholds. This analysis included near-field locations within the Class II area, especially at any sensitive areas within 40 km. No areas within that distance were identified at this time. As a result, 40 km was the distance used for the source to observer and source to nearest Class I area boundary.

Modeling Results for Visibility Impacts

Background	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Critical	Plume	Critical	Plume
Sky	10	55	35.8	114	6	1.654	0.15	0.001
Sky	140	55	35.8	114	6	0.599	0.15	-0.010
Terrain	10	0	1.0	168	6	0.889	0.15	0.009
Terrain	140	0	1.0	168	6	0.263	0.15	0.009

None of the critical levels, or thresholds, were exceeded by the plume, or impacts at a distance of 40 km.

X. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations listed in OAC 252:100, Appendix Q. These requirements are addressed in the “Federal Regulations” section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in “attainment” of these standards.

OAC 252:100-5 (Registration, Emissions Inventory and Annual Operating Fees) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories were submitted and fees paid for previous years as required.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility that result in emissions not authorized in the permit and that exceed the “Insignificant Activities” or “Trivial Activities” thresholds require prior notification to AQD and may require a permit modification. Insignificant activities refer to those individual emission units either listed in Appendix I or whose actual calendar year emissions do not exceed the following limits.

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAP or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule

Emission limitations and operational requirements necessary to assure compliance with all other applicable requirements for all sources are taken from the permit application, initial TV permit, from the various modifications based on the initial TV permit, from the TVR and construction permit applications, Civil Action No. 08-CV 020-D, or are developed from the applicable requirement.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]

Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for affirmative defense, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

OAC 252:100-13 (Open Burning) [Applicable]

Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter (PM)) [Applicable]

Section 19-4 regulates emissions of PM from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating. Appendix C specifies PM emission limitations for all equipment at this facility. Fuel-burning equipment is defined in OAC 252:100-19 as any internal combustion engine or gas turbine, or other combustion device used to convert the combustion of fuel into usable energy. The flares of EUG-12 are not pieces of fuel-burning equipment under the state definition and are not affected by this rule.

All fuel-burning equipment uses gaseous fuel. AP-42 (7/98) Table 1.4-2 lists natural gas total PM emissions to be 7.6 lbs/million scf or about 0.0076 lbs/MMBTU, which is in compliance. The following equipment is subject to the requirements of this subchapter.

Equipment	Maximum Heat Input (MMBTUH)	Emissions (Lbs/MMBTU)	
		Appendix C	Potential Rate
Boilers 1, 2, 3, 4	233 each	0.28	0.008
CDU atmospheric heater	248	0.28	0.008
CDU vacuum heater	100	0.36	0.008
FCCU B-2 heater	165	0.32	0.008
FCCU B-1 heater	38.4	0.44	0.008
Unifiner H-1 heater	42	0.43	0.008
TGTU #2	12.1	0.58	0.008
SCAN charge heater	25.2	0.48	0.008
NHDS charge heater	39	0.44	0.008
NHDS stripper/reboiler	44.2	0.42	0.008

Equipment	Maximum Heat Input (MMBTUH)	Emissions (Lbs/MMBTU)	
		Appendix C	Potential Rate
CCR interheater #1	155	0.32	0.008
DHTU charge heater	55	0.40	0.008
CCR charge heater	120	0.33	0.008
CCR interheater #2-1	101	0.35	0.008
CCR interheater #2-2	25	0.48	0.008
CCR stabilizer/reboiler	85	0.36	0.008
Naphtha Splitter Reboiler	75	0.37	0.008
CCR Helper Heater	25	0.48	0.008
Naphtha HDS Helper Heater	10	0.60	0.008
Diesel Hydro Helper Heater	45	0.42	0.008
ROSE Heater	42	0.43	0.008
007-J-26G	0.6	0.6	0.01
008-PA-50	0.6	0.6	0.01
050-G-1M	0.53	0.6	0.01
004-G-1	0.83	0.6	0.01
012-G-1M	3.37	0.6	0.01
045-G-1M	2.88	0.6	0.01
006-PE-80M	0.36	0.6	0.01
009-PE-143	5.6	0.6	0.09
009-PE-144	1.73	0.6	0.28
033-EG-5320	5.6	0.6	0.09
009-PE-152	3.04	0.6	0.03

Subchapter 19 also limits PM emissions from various processes which are both process and fuel-burning equipment. Limitations are specified based on process weight rate. The process weight at the FCCU is the sum of the catalyst circulation rate (up to 960 TPH) plus the gas oil charge rate. Assuming a specific gravity of 1.05 and a feed rate up to 1,000 BPH, a gas oil feed rate of 184 TPH is calculated for a total process weight rate of 1,144 TPH. The following table shows the process weight rates, allowable PM emissions rates, and permit limitations. The anticipated PM emissions rate from the FCCU is in compliance with Subchapter 19.

**COMPARISON OF PM EMISSION RATES TO ALLOWABLE EMISSION RATES
UNDER OAC 252:100-19**

Process Unit	Process Weight, TPH	OAC 252:100 -19 Allowable PM Emissions, lb/hr	PM Emissions, lb/hr
FCCU	1,144	79.3	17

OAC 252:100-25 (Visible Emissions and Particulates)

[Applicable]

No discharge of greater than 20% opacity is allowed except for short-term occurrences that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. The flares are potential sources of visible emissions at this facility. Proper operation of the smokeless flares should maintain compliance.

Subsection 25-5(a) requires continuous monitoring of opacity at the FCCU catalyst regenerator. The June 30, 2008 CD required compliance with the opacity standard of NSPS Subpart J no later than June 30, 2008. According to §25-5(c), sources required to comply with an opacity standard are exempt from §25-5(a), thus the regenerator is no longer subject to Subchapter 25. This subsection also applies to fossil-fueled steam generators with heat input greater than 250 MMBTUH. None of the refinery equipment meets this threshold.

OAC 252:100-29 (Fugitive Dust)

[Applicable]

No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Heavy traffic areas, including the racks and the offices, are paved. Vehicular traffic in the unpaved areas is greatly restricted for safety reasons. Under normal operating conditions, this facility will not cause fugitive dust problems, therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds)

[Applicable]

Part 5 covers new equipment standards.

In particular, section 31-25 addresses sulfur oxides. New gas fuel-burning equipment, such as the process heaters of EUG 25 and EUG 29 or the modified process heaters of EUG 9 and EUG 26, must meet a standard of 0.2 lbs of SO₂ per MMBTU, three-hour average, per §25(a)(1). Because a permit condition limits H₂S content of the RFG to 0.1 gr/dscm, stoichiometric conversion of all H₂S to SO₂ would yield emissions of 0.027 lbs/MMBTU, well within the limit set forth. Emission monitoring, fuel monitoring, and recordkeeping standards are set in §25(c)(2), but apply to only those items rated at 250 MMBTUH or greater.

Section 31-26(a)(1) covers hydrogen sulfide, setting requirements on the removal efficiency and emission rates for H₂S. The new process units added by the two construction projects mentioned above must meet this standard. All streams containing H₂S are routed to the SRU, whose efficiency at H₂S conversion meets the standard set in §26(a)(1). Using John Zink Company's estimate of incinerator performance (scaled to the expected 25 LTD throughput) yields 0.14 lbs/hr of H₂S emissions. Noting that H₂S input to the incinerator is 82.7 lbs/hr, the efficiency is calculated to be 99.8%, well above the 95% minimum requirement of this section. An emission rate of 0.14 lbs/hr is sufficient to qualify the unit for exemption from the efficiency criterion, because it is well below the 0.3 lbs/hr threshold value.

Section 31-26(a)(2) covers SO₂ recovery standards for the SRUs. Specifically, the two SRUs, rated at 25 LTD, are covered by the standard described in subparagraph D. The SO₂ reduction efficiency requirement for any SRU is defined by the equation $Z = 92.34 \times X^{0.00774}$, where Z is the required efficiency and X is the throughput in LTD. For these SRUs, the result is 94.7%. According to the analysis performed for SRU #1 in Permit No. 98-021-C (M-16), the average emissions of SO₂ are slightly less than 8 lbs/hr. Converting 25 LTD of sulfur to SO₂ equivalent yields an input of 4,667 lbs/hr. The calculated efficiency for SRU #1 is 99.8%, well above the 94.7% threshold. A similar calculation for SRU #2 uses the expected emission rate of 5.6 lbs/hr of SO₂ supplied in the permit application to calculate an efficiency of 99.8%. This number is also well above the acceptable minimum value. Finally, note that both SRUs have emissions of SO₂ well below the 100 lbs/hr threshold necessary to qualify for exemption from the efficiency criteria. Thus, 31-26(2) is not applicable.

OAC 252:100-33 (Nitrogen Oxides)

[Applicable]

This subchapter limits new gas-fired and liquid-fired fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to emissions of 0.20 and 0.30 lbs of NO_x per MMBTU, three-hour average, respectively. Most fuel-burning equipment was installed prior to the effective date of this rule, has not been altered in a manner increasing emissions, and is not subject. The CCR #1 Interheater of EUG 26 is rated at 155 MMBTUH and fits this subchapter's definition of "new." It has a federally-enforceable limit of 0.05 lbs/MMBTU. The heaters of EUG 27 have accepted federally-enforceable limits on NO_x emissions, but modifications performed on them, such as low-NO_x burners, did not have the effect of increasing NO_x emissions, so they are not affected by this subchapter. EUG 27 heaters with input rating greater than 50 MMBTUH are shown in the following table with the limits they have accepted. All of the proposed new heaters at the East Refinery are smaller than 50 MMBTUH. The CDU Atmospheric Tower Heater will have a decrease in NO_x emissions from installation of ULN burners, therefore, will not be "modified" and will not become subject to "new" standards.

Heater	MMBTUH Input	Limit Accepted
DHTU Reactor Charge	55	0.04 lbs/MMBTU
CCR Charge	120	0.05 lbs/MMBTU
CCR #2-1 Interheater	101	0.20 lbs/MMBTU
CCR Stabilizer/Reboiler	85	0.05 lbs/MMBTU
Naphtha Splitter Reboiler	75	0.04 lbs/MMBTU

OAC 252:100-35 (Carbon Monoxide)

[Not Applicable]

The catalytic cracking unit and catalytic reforming unit are existing sources, but are not subject to the standards of Paragraph 35-2(a) because Tulsa County is not a non-attainment area for carbon monoxide. If sufficient modifications were performed to either unit that they might become affected sources, they would meet the new source standards of 35-2(b) because both have complete secondary combustion systems. The FCCU has a monitor to establish that excess oxygen is present in the flue gas. The CRU uses a portable analyzer that establishes that excess oxygen is present at various points in the system. This monitoring is not an OAC 252:100 requirement, and would become so only under the reconstruction or modification situation outlined above. Conversion of the CRU to a CCR under the Low Sulfur Diesel Project covered by Permit No. 98-021-C (M-26) was not sufficient to make this a "new" source, but it meets the

new source standards of 35-2(b) because compliance with the standards of 40 CFR 63 Subpart UUU satisfies the requirements of this subchapter.

OAC 252:100-37 (Volatile Organic Compounds)

[Parts 3 & 7 Applicable]

Part 3 concerns the control of volatile organic compounds.

Section 37-15 (a) requires that all storage tanks with capacity greater than 40,000 gallons and storing a VOC with a vapor pressure greater than 1.5 psia shall be pressure vessels or shall be equipped with one of the following vapor-loss control devices.

(1) They shall be of EFR or fixed roof with IFR design, with the roof floating on the liquid surface at all times and equipped with a closure seal between the roof edge and the tank wall. Floating roofs are not suitable control for liquids with vapor pressure greater than 11.1 psia. All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(2) They shall have an 85% efficient vapor recovery system and a vapor disposal system. All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(3) They shall have other equipment or methods with efficiency at least equal to those devices listed above.

All of the tanks in EUG 1 have capacities greater than 40,000 gallons and are of IFR design. Although they do not all store VOC with vapor pressure greater than 1.5 psia, they satisfy the requirements of this section for doing so.

Many of the tanks in EUG 3 have capacities greater than 40,000 gallons, but none of them stores liquid with vapor pressure greater than or equal to 1.5 psia. All of these tanks are exempt from the provisions of Section 37-15 per §37-4(a).

Tanks in EUG 4 are of various design and are subject to the overlap provisions of MACT CC. All are exempt from the provisions of §37-15 per §37-4(a) or §37-15(c).

Tanks in EUG 13 are smaller than 40,000 gallons. Note that the tanks in EUG 13 are subject to MACT Subpart EEEE.

Tanks in EUG 18 are smaller than 40,000 gallons. Note that the tanks in EUG 18 are subject to MACT Subpart GGGGG.

The tanks of EUG 20 have capacities greater than 40,000 gallons and are EFR tanks subject to NSPS Subpart Kb. They are exempt from the provisions of Section 37-15 per §37-15(c).

All of the tanks in EUG 21 and EUG 22 have capacities greater than 40,000 gallons and store liquids with vapor pressures greater than 1.5 psia. All of these tanks are pressure vessels and satisfy the requirements of §37-15(a).

Section 37-15 (b) requires storage tanks with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system per §37-15(a)(2). All of the tanks identified in the discussion of Subsection 15(a) satisfy the submerged fill condition. Tank #419 is listed as an Insignificant Activity. It has capacity less than 40,000 gallons but greater than 400 gallons and stores gasoline, whose vapor pressure exceeds 1.5 psia. It has submerged fill and satisfies the requirements of this section.

Tanks in EUG 18 satisfy the requirements of MACT Subpart GGGGG, which are more stringent than the requirements of §37-15.

Section 37-16 establishes standards for the loading of volatile organic compounds. Loading racks in EUG 14, including black oil railcar loading, black oil truck loading, diesel railcar loading and gas oil truck loading all involve material with vapor pressure well below 1.5 psia, and are exempt from the provisions of this section per §37-4(a).

Section 37-16 (a) contains requirements for loading facilities with throughput greater than 40,000 gallons per day. These conditions include a vapor collection and disposal system unless all trucks or trailers are bottom-loaded with hatches closed. Additionally, no drainage is allowed from the loading device after disconnection. The racks of EUG 15, including butane truck loading and propylene railcar and truck loading, and propane truck loading all have throughput capability of 40,000 gallons per day. Each of these processes is bottom-loading with hatches closed and all connectors shut automatically or are drained before disconnection. The facility should be considered to be exempt from these provisions. Although Section 37-16 (c) does not specifically exempt sources subject to MACT Subpart CC, it does exempt those subject to MACT Subpart R or NSPS Subpart XX. The rack is subject to MACT Subpart CC, which specifically requires compliance with the standards of both MACT Subpart R and NSPS Subpart XX. The HSR rack does not load trucks or railcars, so it is not subject to §16(a).

Part 5 limits the organic solvent content of coating or other operations. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is not an affected operation.

Part 7 regulates specific processes.

Section 37-36 requires fuel-burning equipment to be operated and maintained so as to minimize emissions. The flares of EUG 12 are not considered to be fuel-burning equipment and are not affected sources. The boilers of EUG 8, the process heaters of EUGs 9, 25, 26, 27, 29, and 33 and the TGTUs of EUG 10 are affected sources. Proper maintenance and operation to provide essentially complete combustion provide compliance.

Section 37-37 concerns water separators that receive water containing more than 200 gallons per day of VOC. The only equipment that may be affected by this section are the “API separators” at the WWTP and Tank 475 of EUG 20, designed for storage of off-test water at the WWTP. These EFR tanks are subject to NSPS Subpart Kb and compliance with the requirements of 40 CFR 60.112b(a)(2) satisfies the requirements of OAC 252:100-37-37(2). However, the section is not applicable to either of these situations because testing of the effluent has shown it to involve material with vapor pressure well below 1.5 psia, leaving both exempt from the provisions of this section per §37-4(a).

OAC 252:100-39 (VOC in Non-attainment Areas)

[Applicable]

Part 3 affects petroleum refinery operations.

Section 39-15 concerns petroleum refinery equipment leaks and is frequently referred to as LDAR, for Leak Detection and Reporting. It applies to all components that might have leaks of VOC when tested by EPA Reference Method (RM) 21 as found in the NSPS regulations of 40 CFR 60. For the purposes of this section, VOC with vapor pressure less than 0.0435 psia is exempt. Standards and operating procedures are set out in §39-15(c), as summarized following.

- 1) Monitor per Section (f), record leaking components and tag each component. Repair and retest leaking components and identify those that cannot be repaired until turnaround. Seal all lines ending with a valve with a second valve, flange, plug, or cap.

- 2) AQD may require remedial action based on the number and severity of tagged components awaiting repair.
- 3) Pipeline and pressure relief valves shall be marked in a manner obvious to both monitoring and DEQ personnel.

Monitoring requirements are found in §39-15(f), as summarized following.

- 1) Monitoring shall consist of annual RM 21 testing for pump seals, pipeline valves in liquid service, and drains, quarterly RM 21 testing for compressor seals and for pipeline valves and pressure relief valves in gas service, and weekly visual monitoring for all pump seals. Further, monitoring shall occur within 24 hours for any pump seal from which VOC liquids are observed dripping and for any relief valve that has vented to the atmosphere. Any leaking component shall be monitored immediately after repair.
- 2) Vapor recovery devices, inaccessible valves, storage tank valves, valves not externally regulated, and pressure relief devices connected to a flare header are exempt from (1) provided that inaccessible valves will be monitored during turnarounds.
- 3) Any leaking component not immediately repaired shall have a readily visible dated identifying tag attached until it is repaired.

Record keeping and reporting requirements are identified in §39-15(g) and (h), and will be more fully enumerated in the Specific Conditions of the permit. The facility states that it is in compliance with all of the requirements listed above.

Section 39-16 concerns petroleum refinery process unit turnarounds and outlines procedures to be used during the planned shutdown, inspection, repair, and restart of a unit. VOC in the unit shall be routed to a flare or vapor recovery system until the unit is blown down to pressure compatible with the control device pressure. The system may then be purged using appropriate materials. The unit may not be vented to atmosphere until unit pressure is less than 5 psig. VOC may not be emitted to the atmosphere through any control device unless it is burned in a smokeless flare or equivalent device, except for special circumstances. Written notice of the unit to be shut down, the date of shut down and the amount of VOC emissions anticipated shall be provided to AQD at least 15 days in advance. Scheduled turnarounds may be exempted from the control requirements during non-oxidant season if the required notice makes a specific request to that effect. The facility has provided the appropriate notices for past turnarounds and is in compliance.

Section 39-17 concerns non-condensable VOC emitted from equipment used in producing vacuums. Only the vacuum tower at the CDU is affected by this section.

Section 39-17(b) requires that non-condensable VOC from steam ejectors with barometric condensers, steam ejectors with surface condensers, and mechanical vacuum pumps shall be incinerated or reduced by 90% through other means. As mentioned in the Process Description, the vacuum tower has steam ejectors with surface condensers. Vacuum tower overhead enters a four-stage ejector system. Discharge from the first three ejectors is sent to water-cooled surface condensers. Under normal operations, discharge from the fourth ejector is sent to the FCCU “wet gas” compressor known as J-50. That gas is then treated at the FCCU amine treater and sent to RFG. In the event that J-50 is not operating, gas from the fourth ejector is vented into the flare system.

Subsection 39-17(c) requires that non-condensable VOC from hotwells and accumulators shall be incinerated and that these pieces of equipment shall be covered. Hotwells are associated with barometric condensers, of which there are none. Vacuum tower overhead condensate from the surface condensers discussed above flows to a pressure vessel (FA-30) that is an accumulator. Any additional vapor from this system is handled with the non-condensable vapors emitted from the fourth ejector, as described above. Subsection 17(c) also requires that the presence of a pilot flame be monitored by any of several means. Heaters at the CDU, as well as those facility heaters using RFG, have pilot flame sensors.

Section 39-18 concerns refinery effluent water separators. The only equipment that may be affected by this section are the “API separators” at the WWTP and Tank 475 of EUG 20, designed for storage of off-test water at the WWTP and authorized by Permit No. 96-227-O. The section is not applicable to either of these situations because testing of the effluent has shown it to involve material with vapor pressure well below 1.5 psia, leaving both exempt from the provisions of this section per §39-4.

Part 5 concerns petroleum processing and storage.

Section 39-30 affects petroleum liquid storage in external floating roof EFR tanks of capacity greater than 40,000 gallons located in Tulsa County. While the facility contains numerous tanks fitting this description, each tank is subject to an NSPS subpart and/or to MACT Subpart CC. Tanks subject to NSPS Subparts K, Ka, or Kb, are exempt from this section per §39-30(b)(3). Tanks subject to NESHAP MACT Subpart CC are exempt from this section per §39-30(b)(4). Thus, all tanks potentially subject to §39-30 are exempt.

Part 7 contains rules affecting specific processes.

Sections 39-41(a) & (b) extend the “new” tank requirements of OAC 252:100-37-15 to existing tanks that store gasoline or other organic materials with vapor pressure greater than 1.5 psia. See the 37-15 discussion above. This facility meets these requirements.

Section 39-41(c) contains provisions concerning loading of VOC. NESHAP 40 CFR 63 Subpart CC had an effective date of August 18, 1998, for the loading facility. This MACT Standard references both NESHAP MACT Subpart R and NSPS Subpart XX. Because these subparts impose conditions at least as stringent as this paragraph, and because the facility is in compliance with Subpart CC, the current requirements should be satisfied.

Subsection 39-41(e) contains provisions pertinent only in Tulsa County. Storage system requirements are extended to gasoline or VOC storage tanks with capacities between 2,000 and 40,000 gallons. No tanks at this facility meet these criteria. It also requires that the stationary loading facility be checked annually using EPA Method 21. Leaks greater than 5,000 ppmv shall be repaired within 15 days. The facility appears to be in compliance. Finally, there are additional controls with respect to transport vessels. The vessels must be maintained vapor tight and must be capable of receiving and storing vapors for ultimate delivery to a vapor recovery/disposal system. Any defect that impairs vapor tightness must be repaired within five days. Certification of vapor tightness and of repairs must be provided and no vessel shall be loaded without demonstrating the proper certification. DEQ may perform inspections of vapor tightness and may require owner/operators to make necessary repairs. This facility and the transports loading there have been in compliance.

Section 39-42 concerns metal degreasing. Sections (b) and (c) cover vapor type and conveyorized degreasing, neither of which is present at this facility. Section (a) covers cold cleaning units, requiring a cover on the unit that can be easily operated with one hand, an internal drain board that allows the cover to close if practical; if not practical, provide external drainage, and that a conspicuous label summarizing proper operation be attached to each such unit. The operating standards for the label are enumerated in Paragraph (a)(2).

OAC 252:100-40 (Friable Asbestos During Demolition & Renovation Operations) [Applicable]
Section 40-5 describes additional procedures for the proper handling of asbestos. These procedures are detailed in the Specific Conditions.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
This subchapter regulates toxic air contaminants (TAC) that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained unless a modification is approved by the Director. Since no Area of Concern (AOC) has been designated anywhere in the state, there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

The following Oklahoma Air Quality Rules are not applicable to this facility.

OAC 252:100-11	Alternative Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Feed & Grain Facility	not in source category
OAC 252:100-47	Municipal Solid Waste Landfills	not in source category

XI. FEDERAL REGULATIONS

PSD, 40 CFR Part 52

[Applicable]

Emissions of several regulated pollutants exceed the major source level of 100 TPY for a listed source. PSD will apply to any future project whose added emissions exceed the significance levels: CO 100 TPY, NO_x 40 TPY, SO₂ 40 TPY, PM_{2.5} 10 TPY, PM₁₀ 15 TPY, VOC 40 TPY, or GHG 75,000 TPY.

NSPS, 40 CFR Part 60

[Subparts A, J, Ja, K, Kb, UU, GGG, GGGa, QQQ, IIII, and JJJJ are Applicable]

Subparts D, Da, Db, Dc (Steam Generating Units)

These subparts apply to steam generating units of various sizes constructed, modified, or reconstructed after various dates. Common to the definition of all affected facilities is the requirement that these devices combust fuel, which would exclude the use of waste heat used in heat exchangers to produce steam. Subpart Dc expands the definition slightly to include the heating of a heat transfer medium, but explicitly excludes process heaters from being affected facilities. Generation of steam at HRMT occurs at the boiler house (BoHo) or in the heat exchangers, so only the BoHo is capable of being an affected facility. All four boilers were constructed in the 1950s, well before August 17, 1971, the earliest effective date of any of these subparts. Any work performed on these boilers since 1971 has been insufficient to meet the modification or reconstruction standards. Add-on controls required by the CD do not constitute modification or reconstruction.

Subpart J (Petroleum Refineries)

Fluid catalytic cracking unit (FCCU) catalyst regenerators, fuel gas combustion devices (FGD), and Claus sulfur recovery plants except Claus plants producing less than 20 long tons per day are all affected facilities under this subpart. Flares may be considered to be FGDs under specific circumstances and would thus be affected facilities. With certain exceptions, the effective date for all affected facilities is June 11, 1973. The FCCU and most FGDs were constructed in 1949 or 1972, prior to the effective date. Although many changes have been made in the handling of waste heat, such as through the efficient use of heat exchangers, most FGDs remain unmodified. SRU #1 was constructed in 1972 and produces 15 long tons per day. Most work performed on the FCCU or FGDs since 1973 has been insufficient to meet the modification or construction standards. However, construction work for the SCAN and Low Sulfur Diesel projects authorized by Permit Nos. 98-021-C (M-16) and 98-021-C (M-26) has modified certain units and added other new units, all now subject to Subpart J. Both SRUs are now subject as are the heaters identified as CCR Stabilizer Reboiler, CCR #1 Interheater, SCAN Charge, NHDS Charge, and NHDS Stripper Reboiler. Under the terms of the CD 08CV 020-D, FGDs at the refinery are subject to the subpart, effective June 30, 2008 and December 31, 2010. Standards required for these equipment items may be found in Specific Conditions covering EUGs 8, 9, 10, 25, 26, and 27. The CD also states that the catalyst regenerator at the FCCU is an affected facility, but with staged compliance dates. Compliance with the CO standard was required on June 30, 2008, and compliance with the SO₂ and PM₁₀ standards was December 31, 2009. See the discussion of NSPS Subpart Ja for further detail concerning the CO requirement.

Subpart Ja, Petroleum Refineries. On June 24, 2008, EPA promulgated standards for new, modified, or reconstructed affected facilities at petroleum refineries. The provisions of this subpart apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCCU), delayed coking units, fuel gas combustion devices, including flares and process heaters, and sulfur recovery plants. Only those affected facilities that begin construction, modification, or reconstruction after May 14, 2007, are subject to this subpart.

Under 40 CFR Part 60.100a(c)(1), adding any new piping from a process unit to a flare is explicitly considered a modification, making the flare subject to Subpart Ja flaring volume limits (250,000 SCF/day, 30-day rolling average) in 40 CFR Part 60.102a(g)(3), the work practice standards of 40 CFR 60.103a, and performance testing requirements under 40 CFR Part 60.8. Between the modifications which have occurred and which are proposed, all flares will be treated as being subject to Subpart Ja.

Fuel gas combustion device means any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid. The new heaters EUG-29 and the modified CDU Atmospheric Tower Heater are considered fuel gas combustion devices which commenced construction after May 14, 2007, and are subject to the final standards promulgated in this subpart. Those heaters are subject to a limitation of sulfur in fuel of 162 ppm (3-hour average) and 60 ppm (annual average). The BACT limitation is equal to the annual limit, therefore, more stringent.

Subpart Ja included NO_x standards for units which are larger than 40 MMBTUH capacity. Two of the proposed new heaters are larger than the 40 MMBTUH threshold. The heaters are subject to a limitation of 0.04 lb/MMBTU NO_x for natural draft units and 0.06 for forced draft units. The BACT limitations are more stringent than Subpart Ja for NO_x. The CDU Atmospheric Tower Heater will have a decrease in NO_x, therefore, will not become subject to these standards.

Subparts K, Ka, Kb (VOL Storage Vessels)

There are many tanks to consider. The earliest effective date of any of these subparts is June 11, 1973. All but ten of the hydrocarbon storage tanks were constructed before that date. They have not been modified or otherwise altered to sufficient extent to meet the reconstruction or modification criteria, and are not affected sources. Subpart Kb excludes vessels storing organic liquids with vapor pressures below 3.5 kPa (0.5 psia).

Subpart K

Tank #13 in EUG 4 has capacity greater than 65,000 gallons, was constructed in 1976, and is an affected source per 40 CFR 60.110(c)(1). Standards contained in §112 require a floating roof for stored liquids with true vapor pressure (TVP) greater than 1.5 psia and a vapor recovery system for liquids with TVP greater than 11.1 psia. Tank #13 is of internal floating roof construction and does not contain liquids with TVP greater than 11.1 psia. Monitoring requirements are described in §113 and include recording the liquid stored, the period of storage, and the maximum TVP during the storage period.

Subpart Ka

None of the tanks was constructed after May 18, 1978, and before July 23, 1984, within the applicability window for Subpart Ka.

Subpart Kb

Tanks in EUG 20 were constructed after July 23, 1984. Tanks 476 and 478 meet these standards with external floating roofs (EFR) with primary and secondary seals, and satisfy the requirements of §112b(a)(2)(i - iii).

The facility is permitted to add tanks whose VOC emissions do not exceed a cap. It is presumed these new tanks will all be subject to Subpart Kb.

Subpart GG (Stationary Gas Turbines)

There are no gas turbines at this facility.

Subpart UU (Asphalt Processing and Asphalt Roofing Manufacture)

Affected facilities at refineries are each asphalt storage tank and asphalt blowing still. HRMT has no blowing stills. The storage tanks have been moved to the HEP permit except for the tanks in EUG-3, which will be shown in the permit as being subject to Subpart UU

Subparts VV and VVa (VOC Leaks in SOCFI)

Several subparts of NSPS make reference to Subpart VV, but these references do not make equipment items or processes directly subject to Subparts VV or VVa. Propylene, a product listed in these subparts, is manufactured by the refinery. Regardless of the preceding comments, it has been determined that the refinery is currently subject only to Subpart GGG or GGGa, which are discussed below.

Subpart XX (Bulk Gasoline Terminals)

This subpart applies to loading racks at bulk gasoline terminals for which construction or modification commenced after December 17, 1980. The gasoline loading terminal has been moved to another permit.

Subpart GGG (VOC Equipment Leaks in Petroleum Refineries)

A compressor is an affected facility and the group of all equipment within a process is an affected facility. The word "equipment" in the preceding sentence is defined in 40 CFR 60.591 to mean each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. Any affected facility that commences construction or modification after January 4, 1983, and before November 7, 2006, is subject to the requirements of this subpart. Much of the refinery was constructed or modified well before 1983, but numerous facilities listed in Section III: Equipment meet the applicability criteria used here. They are identified in the Specific Conditions, as necessary.

Subpart GGGa (VOC Equipment Leaks in Petroleum Refineries)

This subpart affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at a process unit, which commenced construction or modification after November 7, 2006, and which is located at a petroleum refinery. This subpart defines “process unit” as “components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates: a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.” Subpart GGGa requires the leak detection, repair, and documentation procedures of NSPS, Subpart VVa. All affected equipment which commenced construction or modification after November 7, 2006, in VOC service is subject to this subpart, including the modified CCR and DHTU and the Naphtha Splitter Reboiler Unit. This project will include construction of the new LPG, ROSE, and Naphtha Fractionation Column units, and modification of the CCR, DHTU, NHDS, and ALKY Units. All applicable requirements have been incorporated into the permit.

Subpart KKK (VOC Equipment Leaks / Onshore Natural Gas Processing Plants)

No natural gas processing occurs at this facility.

Subpart LLL (Onshore Natural Gas Processing: SO₂ Emissions)

No natural gas processing occurs at this facility.

Subpart QQQ (VOC from Petroleum Refinery Wastewater Systems)

Affected facilities include each individual drain system, each oil-water separator, and each aggregate facility, where aggregate facility is the subject of further definition. Facilities constructed, modified, or reconstructed after May 4, 1987, are subject to the requirements of this subpart. Many of the facilities in the refinery were built before the effective date and are not subject. Construction of the SCAN and Low Sulfur Diesel projects under Permit Nos. 98-021-C (M-16) and 98-021-C (M-26) created several drain systems potentially subject to Subpart QQQ. These systems include all drains at SCAN, NHDS, and SRU #2. New drains installed during modification of the HTU to DHTU and modification of the CRU to CCR are also affected. Systems are grouped as Group 1 or Group 2 under Refinery MACT Subpart CC (q.v.), where Group 1 members are those emission points to which control criteria apply. Under this division, Group 1 activities are subject to the standards of MACT Subpart CC, while Group 2 activities are subject to QQQ, if they meet the applicability criteria. An Applicability Determination issued June 11, 2007, by George Czerniak of EPA, indicates that if a facility identifies a Group 2 system as Group 1, and subjects it to the control standards of NESHAP Subpart FF, that system is exempt from NSPS QQQ. All of the mentioned systems are exempt from QQQ, but they remain subject to MACT CC. Tanks subject to NSPS Subpart Kb are not subject to the standards of Subpart QQQ, but they are subject to overlap provisions in MACT Subpart CC. Specific Conditions address these overlaps. There will be new process drains in the new ROSE and Naphtha Fractionation Column Units, but by the overlap provisions of MACT Subpart CC, the new drains are subject only to the MACT.

Subpart JJJJ, Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (SI-ICE). This subpart was published in the Federal Register on January 18, 2008. It promulgates emission standards for new SI engines ordered after June 12, 2006 and all SI engines modified or reconstructed after June 12, 2006, regardless of size. The emergency engines in EUG-34a are subject to emergency engine standards under Subpart JJJJ.

Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, affects stationary compression ignition (CI) internal combustion engines (ICE) based on power and displacement ratings, depending on date of construction, beginning with those constructed after July 11, 2005. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator. The emergency engines in EUG-35a are subject to emergency engine standards under Subpart IIII.

NESHAP, 40 CFR Part 61

[Subparts M and FF Applicable]

Of the pollutants listed in 40 CFR 61 (asbestos, benzene, beryllium, coke oven emissions, inorganic arsenic, mercury, radionuclides, and vinyl chloride), only asbestos and benzene are emitted by this facility. Several subparts cover emissions of benzene but all product streams are less than the 10% threshold.

Subpart J (Equipment Leaks) The overhead from the reformat splitter will contain >10% benzene, but the facility is only required to comply with the MACT CC Equipment Leak provisions as described in the overlap provisions found in 40 CFR 63.640(p).

Subpart L (Coke By-Product Recovery) This facility is not an affected source.

Subpart M (Asbestos) applies to this facility. HRMT is involved in the removal of asbestos and shall abide by the applicable requirements of §61.145.

Subpart Y (Benzene Storage Vessels) This facility is not an affected source.

Subpart BB (Benzene Transfer Operations) This facility is not an affected source.

Subpart FF (Benzene Waste Operations) This facility is a petroleum refinery and is an affected source per 40 CFR 61.340(a). Sections (b) and (c) contain requirements implying coverage by §§61.343 (Tanks), 61.344 (Surface impoundments), 61.345 (Containers), 61.346 (Individual drain systems), 61.347 (Oil-water separators), 61.348 (Treatment processes), and 61.349 (Closed-vent systems and control devices). Sections 61.350-352 cover alternative methods. Sections 61.354-6 concern monitoring, recording, and reporting benzene wastes, and contain a great amount of detail on these topics.

NESHAP, 40 CFR Part 63

[Subparts CC and UUU Applicable]

Subpart Q (Industrial Process Cooling Towers)

This subpart applies only to cooling towers using chrome. None is used by the facility.

Subpart R (Gasoline Distribution Facilities)

The gasoline loading rack has been moved to the HEP permit.

Subpart CC (Petroleum Refineries)

Various process units and related emission points at petroleum refineries may be affected sources. They must be located at a plant site that is a major source per §112(a) of the Clean Air Act and they must emit or have equipment containing or contacting any of the organic HAP listed in Table 1 of the subpart. Table 1 contains only 28 chemicals, including meta-, ortho-, para-, and mixed isomers of both cresol and xylene. Organic HAP, as used in this subpart, refers

only to chemicals on this list of 28. HRMT/HEP is an affected facility. Following are the source categories listed in 40 CFR 63.640(c) and a summary of applicable requirements for each.

- (c)(1) Miscellaneous process vents from petroleum refining process units. Vents identified as Group 1 vents are those having VOC emissions of at least 33 kilograms (73 pounds) per day from existing sources or at least 6.8 kilograms (15 pounds) per day from new sources, both measured after any final recovery device, but before any control device or discharge to the atmosphere. The VOC emissions must have organic HAP concentrations of at least 20 ppmv. Either of two requirements described in §643 shall be used for these emissions; a flare that meets the standards of 40 CFR 63.11(b), or a control device that reduces the organic HAP content by 98% by weight, or to 20 ppmv dry, corrected to 3% oxygen. If a boiler or process heater is used for the second option, the vent stream shall be introduced into the flame zone. With one exception, all process vents have been routed to one of the flares or to the refinery fuel gas (RFG) system. With the new flare gas recovery system, all but those large events caused by malfunction will be routed to RFG. Emissions routed to the RFG system are not affected sources, per §640(d)(5). Emissions from the surface condensers in the vacuum tower at the CDU are currently piped directly into the flame zone of the unit process heater, satisfying the requirements of §643(b) and obviating the need for monitoring per §644(a)(3).
- (c)(2) Storage vessels associated with petroleum refining process units. Group 1 storage vessels are required to comply with §§63.119 through 63.121 of Subpart G except as provided for in §63.646(b) through (l). Group 1 storage vessels for an existing source are those vessels with design capacity at least 177 m³ (46,758 gallons), storing a liquid with a maximum true vapor pressure at least 10.4 kPa (1.5 psia) and annual average true vapor pressure at least 8.3 kPa (1.2 psia), and storing a liquid with an annual average organic HAP concentration greater than 4 percent by weight. Subpart G is the MACT for Process Vents, Storage Vessels, Transfer Operations, and Wastewater at Synthetic Organic Chemical Manufacturing Industries (SOCMI). Most of the exceptions are simply substitute language to properly identify references and terminology; any substantive exceptions will be identified in the Specific Conditions of this permit. The sections cited essentially repeat the language of NSPS Subpart Kb. The compliance date for new tanks is first operation, and the compliance date for all existing tanks was August 18, 2005.

Because of overlap provisions to conform treatment of storage vessels with other NSPS or NESHAP Subparts, each EUG containing storage vessels is addressed separately.

EUG 4 - Wastewater tanks. Overlap provisions with NSPS Subparts Kb and QQQ, NESHAP Subpart FF, and MACT CC, including references to MACT G, require demonstration of compliance with NSPS Subpart Kb to satisfy all requirements.

EUG 18 - MACT GGGGG tanks. None of these tanks is subject to MACT CC.

EUG 20 - EFR tanks subject to NSPS Subpart Kb. Compliance with Subpart Kb is sufficient.

- (c)(3) Wastewater streams and treatment operations associated with petroleum refining process units. A Group 1 wastewater stream is one with a total benzene load of at least 10 megagrams (Mg) per year (11 TPY), a flow of at least 0.02 liters per minute (0.32 gph), a benzene concentration of at least 10 ppm, and not exempt from the control requirements of NESHAP Subpart FF. HRMT's wastewater stream exceeds 10 Mg per year and is subject to 40 CFR 61 FF. Individual streams may be exempted from control requirements if they contain more than 10% water by volume, provided that the total benzene content of such exempted streams does not exceed 6 Mg per year. Exemptions of such streams must be demonstrated and documented.
- (c)(4) Equipment leaks from petroleum refining process units. The standards for all equipment are found in 40 CFR 60 Subpart VV, with certain minor exceptions. Among these are the necessary corrections to definitions of organic HAP as found in MACT CC and the requirement that all records be maintained for at least five years. Exceptions as to new sources, hydrogen service, and others are described in the Specific Conditions.
- (c)(5) Gasoline loading racks classified under SIC code 2911 shall comply with the standards of 40 CFR 63 Subpart R, with the only exception relating to the definition of organic HAP. The gasoline loading terminal has been moved to the Holly Energy Partners permit.
- (c)(6) Marine vessel loading operations. HRMT has none.
- (c)(7) Storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station classified under SIC code 2911 contiguous to and under common control with a refinery. The gasoline loading terminal has been moved to the HEP permit.
- (c)(8) Heat exchange systems. Specifications for "Heat exchange system" have been added as 40 CFR Part 63.654. A facility is exempt from these standards if a cooling tower operate with a pressure difference of at least 5 psia between the cooling water side and process side, or employ an intervening cooling fluid with is less than 5% organic HAPs. Otherwise, the operator must perform monitoring to identify leaks and repair those leaks. There are separate standards for closed-loop systems and once-through systems.

Various sources are explicitly named in 40 CFR 63.640(d) as not being affected sources, including the following.

- (d)(1) Storm water from segregated storm water sewers.
- (d)(2) Spills.
- (d)(3) Any pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve or instrumentation system that is intended to operate in organic HAP service less than 300 hours per year.
- (d)(4) Catalytic cracking unit and catalytic reformer catalyst regeneration vents and sulfur plant vents.
- (d)(5) Emission points routed to a fuel gas system, as defined in §641. No testing, monitoring, recordkeeping, or reporting is required for RFG systems or for emission points routed to RFG systems.

Subpart UUU (Petroleum Refineries – Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Plant Units)

This final MACT was published in the Federal Register on April 11, 2002; with a general compliance date of April 11, 2005, that was much later than the issuance date of the initial TV permit. The FCCU catalyst regeneration flue vent is subject to metal and organic HAP emissions standards described in §§1564 and 1565 of MACT UUU. Because the FCCU is not currently subject to NSPS Subpart J, the facility chooses to demonstrate compliance using Option 3 of Table 1, which requires that emissions of nickel not exceed 0.029 lbs/hour. Catalytic reforming unit vents, including those at the CCR, are subject to organic HAP emission limits during depressuring and purging events, which includes depressurization, purging, coke burn, catalyst rejuvenation, and reduction or activation purge. The requirements outlined in Table 15 of the MACT are satisfied by compliance with OAC 252:100-39-16, which contains procedures for such events; the MACT is currently complied with by depressurizing into the flare system. The requirements of Table 22 (Option 3 for the CCR) are met by monitoring HCl concentration. The SRUs are subject to NSPS Subpart J, compliance with which satisfies the requirements of MACT UUU.

Subpart EEEE (Organic Liquids Distribution (Non-gasoline)) concerns those organic HAP listed in Table 1 of the subpart and handling equipment, including storage tanks, transfer racks, equipment components, and transport vehicles while at the transfer racks. Criteria described in Table 2 of the subpart indicate that tanks with capacity less than 5,000 gallons are not affected. Except for the loading rack, all components of the HSR loading project are already covered under MACT CC, and are thus exempt from Subpart EEEE per 40 CFR 63.2338(c)(1). Because the rack is not subject to any of the emission limits in Table 2 of this subpart, it is not subject to any other standard except for initial notification under §63.2382(b)(2).

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart was published in the Federal Register on June 15, 2004 and affects existing, new, and reconstructed spark ignition 4-stroke rich-burn (4SRB) RICE, new or reconstructed spark ignition 2-stroke lean-burn (2SLB) RICE, new or reconstructed 4-stroke lean-burn (4SLB) RICE, and new or reconstructed compression ignition (CI) RICE, with a site-rating greater than 500 brake horsepower, that are located at a major source of HAP emissions. Engines which are subject to NSPS Subparts IIII or JJJJ are required to comply with those subparts. Existing spark-ignition 4SRB engines and CI engines are required to comply with the following standards of Subpart ZZZZ:\

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE ¹	a. Change oil and filter every 500 hours of operation or annually, whichever comes first. ² b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. ³	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. ³
6. Emergency stationary SI RICE and black start stationary SI RICE. ¹	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; ² b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. ³	

Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters at major sources of HAPs. This regulation was re-promulgated on December 23, 2012. The new regulation does not specify any standards for gas-fired boilers and heaters.

Subpart GGGGG (Site Remediation) affects various equipment involved in site remediation that emit any of certain HAP identified in the subpart and that are located at sources that are major sources of HAP as defined in 40 CFR 63.2. Process vents, remedial material management units (tanks), and equipment leaks are affected facilities under this subpart. EUG 18 (Hydrocarbon Recovery System) contains equipment affected by this MACT. Because of overlap provisions with other MACT subparts, compliance is satisfied through carbon canisters on the tanks.

CAM, 40 CFR Part 64 [Applicable]
 Compliance Assurance Monitoring (CAM) as published in the Federal Register on October 22, 1997, applies to any pollutant specific emission unit at a major source that is required to obtain a Title V permit, if it meets all of the following criteria.

- It is subject to an emission limit or standard for an applicable regulated air pollutant
- It uses a control device to achieve compliance with the applicable emission limit or standard
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY

Although there have been very few emission limits for sources in the refinery, many sources within the refinery are subject to the standards of 40 CFR 63 Subpart CC or Subpart UUU. Provisions for monitoring contained in these subparts is considered presumptively acceptable monitoring in accordance with 40 CFR 64.4(b)(4). The required explanation of the applicability is found in the discussion for MACTs CC and UUU.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]
 Naturally occurring hydrocarbon mixtures, prior to entry into a natural gas processing plant or a petroleum refining process unit, including condensate, crude oil, field gas, and produced water, are exempt for the purpose of determining whether more than a threshold quantity of a regulated substance is present at the stationary source. Listed materials produced and held for sale as fuel are also exempt. HRMT filed a Risk Management Plan with the EPA on June 21, 1999, and filed a revised and updated plan on June 21, 2004. EPA's file number is 1000 0014 6567.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F are Applicable]
 These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).

Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.

Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.

The Standard Conditions of the permit address the requirements specified at §82.156 for persons opening appliances for maintenance, service, repair, or disposal; §82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; §82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; §82.166 for recordkeeping; §82.158 for leak repair requirements; and §82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

XII. COMPLIANCE

Tier Classification and Public Review

This application has been classified as **Tier II** based on the request for a construction permit for a “significant” modification. The applicant published the “Notice of Filing Tier II Application” in *The Tulsa Business & Legal News* on June 2, 2014. A draft of this permit was also made available for public review for a period of 30 days as stated in another newspaper announcement published on December 23, 2014, and was available for review on the Air Quality section of the DEQ web page at <http://www.deq.state.ok.us>.” The permit was approved for concurrent public and EPA review; the draft/proposed permit was also submitted to EPA for a 45-day review period. No comments were received from the public. EPA submitted several comments which have been acted on where appropriate. Documentation of comments and responses has been placed in the permit files.

This facility is not located within 50 miles of the border with a contiguous state.

Information on all permit actions is available for review by the public in the Air Quality section of the DEQ Web page: www.deq.state.ok.us.

Fee Paid

Part 70 source construction permit application fee of \$7,500.

XIII. SUMMARY

The facility has demonstrated the ability to comply with the requirements of the several air pollution control rules and regulations. Ambient air quality standards are not threatened at this site. Issuance of the permit is recommended.

**PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS**

**Holly Refining & Marketing Company
Tulsa Refinery**

Permit Number 2012-1062-C (M-1)(PSD)

The permittee is authorized to construct in conformity with the specifications submitted to the Air Quality Division (AQD) on May 2, 2014. The Evaluation Memorandum dated April 20, 2015, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction or continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

SPECIFIC CONDITION 1

The permittee shall be authorized to operate the affected facilities noted in this permit continuously (24 hours per day, every day of the year) subject to the following conditions. Records necessary to show compliance with each of the requirements below must be maintained.

[OAC 252:100-8-6(a)(1)]

- a. Combined emissions from Tank 475 and 474 in EUG 20 are limited to 19.578 tons per year (TPY) of volatile organic compounds (VOC). [98-021-TV]
- b. Alkylate production is limited to 6,500 BPD based on a 12-month rolling average.
- c. The following tank has the throughput limits specified below.

Tank No.	EUG	Throughput Limit
476	20	16,261,905 barrels/year

- d. The following units have the noted TPY emission limits. Compliance with all but SO₂ limits are met by throughput limits. See Specific Condition 2, EUG 10 (c) for a description of SO₂ compliance.

EUG	Source	PM₁₀	NO_x	SO₂	VOC	CO
10	SRU #1			34.9		99
10	SRU#2	0.23	4.91	24.6	0.16	*
9	Naphtha Splitter Reboiler	2.3	13.1	8.7	1.8	27.9

*stack testing will be conducted within 12 months of permit issuance to establish CO emissions limits.

SPECIFIC CONDITION 2

Standards for affected Emission Unit Groups (EUG).

[OAC 252:100-8-6(a)]

EUG 3 MACT CC Group 2 Storage Vessels - Fixed Roof (FR)

These storage vessels are regulated under 40 CFR 63 Subpart CC (MACT CC) Group 2 Storage Vessels and are limited to the existing equipment as it is. Due to the overlap provisions of MACT CC §63.640(n), this list includes any Group 2 storage vessels that are also regulated under NSPS K or Ka but are not required to meet any control standards, as they must meet these requirements per §640(n)(7). Storage vessels required to meet control requirements under NSPS K and Ka are required to comply only with those subparts (§640(n)(6)) and are not included in this list.

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
112	6195	2012	30'	110'	50,000
118	6201	1907	30'	96'	37,500
119	6202	1907	30'	96'	37,500
126	6263	1907	30'	96'	37,500

- a. Fixed roof tanks in EUG 3 are subject to only the recordkeeping requirements of MACT Subpart CC for Group 2 storage vessels, as follow. [40 CFR 63.654(i)(1)(iv)]
 1. Readily accessible records showing the dimensions of each vessel and an analysis of the capacity of each vessel shall be maintained for the life of the vessel. [40 CFR 63.123(a)]
 2. Data, assumptions, and procedures used in determining Group 2 status for these tanks shall be documented. [40 CFR 63.646(b)(1)]
- b. The tanks in EUG 3 are subject to 40 CFR Part 60, Subpart UU (Asphalt Processing and Asphalt Roofing Manufacture) and shall comply with all applicable standards:
 1. 60.470: Applicability and designation of affected facilities
 2. 60.471: Definitions
 3. 60.472: Standards for particulate matter
 4. 60.473: Monitoring of operations
 5. 60.474: Test methods and procedures

EUG 4 MACT CC Wastewater Tanks

These storage vessels are regulated under 40 CFR 63 Subpart CC (MACT CC) as wastewater management units and are limited to the existing equipment as it is. Due to the overlap provisions of MACT CC, the requirements of 40 CFR 61 Subpart FF (BWON), and 40 CFR 60 Subpart QQQ (NSPS QQQ), these vessels are required to comply with 40 CFR 60 Subpart Kb to meet the applicable standards under MACT CC, BWON, and NSPS QQQ.

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
13	6243	1976	40'	116'	75,250
400	17035	1922	30'	24'	2,400
401	17036	1920	20'	25'	1,700

¹ Originally Kb tank, converted to wastewater only.

- a. The permittee shall comply with the applicable sections of MACT CC, Wastewater Provisions of 63.647 for the affected storage tanks. [40 CFR § 63.640-654]
 1. The permittee shall comply with the requirements of § 61.340 through § 61.355 of 40 CFR 61 Subpart FF.
To accomplish this, the storage tanks will: [40 CFR 63.647(a)]
 - A. Comply with the Alternative Standards for Storage Tanks of 40 CFR§ 61.351 and 40 CFR 60 Subpart Kb;
 - B. Meet the requirements of 40 CFR § 61.343 for Tanks; or
 - C. Be counted as uncontrolled and included in the 6 BQ calculation under § 61.355(k).
- b. Recordkeeping is required per 40 CFR § 61.356. [40 CFR § 63.654(a)]
- c. Reporting is required per 40 CFR § 61.357. [40 CFR § 63.654(a)]

EUG 6 Continuous Catalytic Reforming Unit (CCR)

The CCR is regulated by 40 CFR 63, Subpart UUU and is limited to inorganic HAP of 10 ppmvd corrected to 3% oxygen at the regenerator stack. [40 CFR 63, Subpart UUU]

- a. The CCR is subject to NESHAP, Subpart UUU and shall comply with all applicable including but not limited to:
 1. § 63.1560 What is the purpose of this subpart?
 2. § 63.1561 Am I subject to this subpart?
 3. § 63.1562 What parts of my plant are covered by this subpart?
 4. § 63.1563 When do I have to comply with this subpart?
 5. § 63.1566 What are my requirements for organic HAP emissions from catalytic reforming units?
 6. § 63.1567 What are my requirements for inorganic HAP emissions from catalytic reforming units?
 7. § 63.1569 What are my requirements for HAP emissions from bypass lines?
 8. § 63.1570 What are my general requirements for complying with this subpart?
 9. § 63.1572 What are my monitoring installation, operation, and maintenance requirements?
 10. § 63.1574 What notifications must I submit and when?
 11. § 63.1577 What parts of the General Provisions apply to me?
 12. Recordkeeping § 63.1576 What records must I keep, in what form, and for how long?
 13. Reporting § 63.1575 What reports must I submit and when?

- b. Performance testing as required by NESHAP Subpart UUU shall be repeated within 180 days of completion of modifications on the CCR. [OAC 252:100-43]

EUG 8 Fired Boilers

The boilers are subject to NSPS Subpart J, effective June 30, 2008. These sources are proposed for regulation under 40 CFR 63 Subpart DDDDD (MACT DDDDD) as initially published on December 23, 2012. At this time, AQD has determined that a 112(j) determination is not needed for sources potentially subject to a proposed MACT, including Subpart DDDDD. This permit may be reopened to address Section 112(j) when necessary. Each boiler is fitted with SCR for control of NO_x and compliance is monitored by CEMs.

ID	Point ID	Manufacturer	Model/Burner type	Construction Date
1	6150	Babcock & Wilcox	FH 26	1950
2	6150	Babcock & Wilcox	FH 26	1950
3	6151	Babcock & Wilcox	FH 26	1950
4	6151	Babcock & Wilcox	FH 26	1955

- a. Nitrogen oxides emissions shall not exceed 0.20 lbs/MMBTU (3-hr average) or 0.03 lb/MMBTU (annual average). Compliance with this standard shall be demonstrated by use of a continuous emissions monitoring system (CEMS) and the reporting/notification requirements of 40 CFR § 60.7. The CEMS shall meet the requirements of 40 CFR 60.13 except that the RATAs shall be required every three years. [CD]

- b. All fuel-burning or refuse-burning equipment shall be operated to minimize emissions of VOC. Among other things, such operation shall assure based on manufacturer's data and good engineering practice, that the equipment is not overloaded; that it is properly cleaned, operated, and maintained; and that temperature and available air are sufficient to provide essentially complete combustion. [OAC 252:100-37-36]

- c. All boilers are subject to 40 CFR 60 Subpart J, and shall comply with all applicable provisions including but not limited to: [40 CFR 60, Subpart J]

1. § 60.104 Standards for sulfur dioxide – (a)(1)
2. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
3. § 60.106 Test methods and procedures – (e)

[40 CFR 60, Subpart J; OAC 252:100-43]

- d. Fuel oil shall not be burned except during periods of gas curtailment, operator training, or test runs. [CD]

e. The sulfur content of gas fuel in fuel-burning equipment shall not exceed 60 ppm, annual average. The sulfur content shall be monitored using a CEMS which complies with NSPS, Subpart Ja. Records of monitoring results shall be kept. [OAC 252:100-8-6(a)]

EUG 9 Existing Fuel-Burning Equipment

Certain heaters have heat input limits, as identified in Specific Condition 1. According to the June 30, 2008 CD, these fuel gas combustion devices (FGDs) are affected facilities under NSPS Subpart J. A compliance date of June 30, 2008 applies to all FGDs, with the exception of the atmospheric and vacuum heaters (ID 6155), which had a compliance date of December 31, 2010.

Source	Point ID	Manufacturer	Burner Type	No. of Burners	MMBTUH (HHV)	Heater Date
Vacuum	6155	Foster-Wheeler	JZ-HEVD-16	14	100 ²	1949
FCCU Charge B-2	6158	M W Kellogg	JZ-VBM-14	32	165 ²	1949
FCCU Air Heater (B-1) ¹	6159	M W Kellogg	Peabody M-18	1	38.4 ²	1949
Unifiner Charge H-1	6167	Refinery Engr	Z-UOV-4 Twin head	12	42 ²	1955

(1) vents to FCCU regenerator stack.

(2) estimated capacities per previous owner (Sinclair); June 1998 DEQ facility inspection; not permit limits.

a. All heaters are affected facilities under NSPS J. All but the atmospheric and vacuum heaters at the CDU shall comply no later June 30, 2008. The atmospheric and vacuum heaters shall comply no later than December 31, 2010. Provisions include, but are not limited to the following. [40 CFR 60, Subpart J; OAC 252:100-43]

1. § 60.104 Standards for sulfur dioxide
2. § 60.105 Monitoring of operations
3. § 60.106 Test methods and procedures

b. All fuel-burning equipment shall be operated and maintained to minimize emissions of VOC. Such conditions mean adherence to manufacturer's recommendations or to good operating and maintenance practices, and that temperature and sufficient air to provide essentially complete combustion are supplied. [OAC 252:100-37-36]

c. Recordkeeping is required as follows:

1. NSPS J records as required under 40 CFR 60 Subpart A. [40 CFR 60.7]
2. H₂S CEM to show compliance with SO₂ emission limits. [OAC 252:100-43]
3. NO_x performance tests for specified heaters. [OAC 252:100-43]

d. Reporting is required for NSPS Subpart J heaters on a semi-annual basis, including the information required in NSPS Subpart A. [40 CFR 60.107 and 60.7]

- b. The sulfur content of gas fuel in fuel-burning equipment shall not exceed 60 ppm, annual average. The sulfur content shall be monitored using a CEMS which complies with NSPS, Subpart Ja. Records of monitoring results shall be kept. [OAC 252:100-8-6(a)]

EUG 10 Sulfur Recovery Units

SRU #1 was constructed in 1972 and SRU #2 became operational in June 2006. Each unit has a tail gas treating unit (TGTU) to scrub its exhaust. The TGTU #1 incinerator is rated at 5.6 MMBTUH and the TGTU #2 incinerator is rated at 12.1 MMBTUH.

- a. SRU #1 and SRU #2 are subject to NSPS J and shall comply with all applicable provisions including but not limited to: [40 CFR 60 Subpart J]
 - 1. § 60.104 Standards for sulfur dioxide – (a)(2)(i);
 - 2. § 60.105 Monitoring of operations – (a)(5)(i & ii) & (e)(4)(i);
 - 3. § 60.106 Test methods and procedures – (a) & (f)(1 & 3).
- b. SRU #1 and SRU #2 subject to NESHAP, Subpart UUU and shall comply with all applicable provisions by the dates specified in § 63.1563(b). [40 CFR 63 Subpart UUU]
 - 1. § 63.1568 What are my requirements for HAP emissions from sulfur recovery units? – (a)(1), (b)(1, 3, 4, 5, 6, & 7), & (c)(1 & 2);
 - 2. § 63.1569 What are my requirements for HAP emissions from bypass lines? – (a)(1 & 3), (b)(1-4), & (c)(1 & 2);
 - 3. § 63.1570 What are my general requirements for complying with this subpart? – (a) & (c-g);
 - 4. § 63.1571 How and when do I conduct a performance test or other initial compliance demonstration? – (a) & (b)(1-5);
 - 5. § 63.1572 What are my monitoring installation, operation, and maintenance requirements? – (a)(1-4) & (d)(1-2);
 - 6. § 63.1574 What notifications must I submit and when? – (a)(2) & (f)(1, 2(i), 2(ii), 2(viii), 2(ix), & 2(x));
 - 7. § 63.1575 What reports must I submit and when? – (a-h);
 - 8. § 63.1576 What records must I keep, in what form, and for how long? – (a), (b)(1, 3, 4, 5), & (d-i);
 - 9. § 63.1577 What parts of the General Provisions apply to me?
- c. Sulfur pit emissions shall be vented so that they are eliminated, controlled, or included and monitored as part of the emissions subject to Subpart J limits, except during maintenance, start-up, shutdown, upset or malfunction.
- d. SRU/TGTU #1 does not have continuous flow monitoring, but it does have CEMS for monitoring concentrations of SO₂ and O₂. Maximum exhaust flow rates established by the most recent performance testing shall be combined with SO₂ CEMS readings to establish hourly and annual SO₂ emissions. Such testing, shall be performed within 60 days after any construction project that increases throughput to the SRU, but at intervals no greater than 12 months. [OAC 252:100-43]

e. Recordkeeping is required as follows.

1. Per NSPS Subparts A and J, including, but not limited to, CEMs information and periods of excess emissions and monitor unavailable time. [40 CFR § 60.107 and 60.7]
2. Per MACT Subparts A and UUU, including, but not limited to, CEMs information, periods of excess emissions, SSM records, performance and RATA tests, and Operations, Maintenance, and Monitoring (OMM) records.

[40 CFR § 63.1576, 63.6, 63.8 and 63.10]

f. Reports are required as follow.

1. Per NSPS Subparts A and J, including, but not limited to, semi-annual compliance reports and CEMs excess emission report. [40 CFR § 60.107 and 60.7]
2. Per MACT Subparts A and UUU, including, but not limited to, semi-annual compliance reports, SSM reports, and CEMs excess emission reports.

[40 CFR § 63.1575, 63.6, 63.8, and 63.10]

EUG 11 FCCU

Emissions Limits:

Pollutant	Emission Limit	Averaging Period	First Compliance Date
SO ₂	25 ppmdv @ 0% O ₂	365 days rolling	December 31, 2010
	50 ppmdv @ 0% O ₂	7 days rolling	January 7, 2010
NO _x	20 ppmdv @ 0% O ₂	365 days rolling	December 31, 2010
	40 ppmdv @ 0% O ₂	7 days rolling	January 7, 2010
PM	1 lb PM / 1000 lbs coke burn-off	3-hours	June 30, 2008
CO	500 ppm@ 0% O ₂	1-hour	June 30, 2008

- a. The FCCU is subject to 40 CFR 63 Subpart UUU (MACT UUU) and shall comply with all applicable requirements including but not limited to: [40 CFR 63 Subpart UUU]

1. §63.1560 What is the purpose of this subpart?
2. §63.1561 Am I subject to this subpart?
3. §63.1562 What parts of my plant are covered by this subpart?
4. §63.1563 When do I have to comply with this subpart?
5. §63.1564 What are my requirements for metal HAP emissions from catalytic cracking units?
6. §63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?
7. §63.1570 What are my general requirements for complying with this subpart?
8. §63.1572 What are my monitoring installation, operation, and maintenance requirements?
9. §63.1574 What notifications must I submit and when?
10. §63.1575 What reports must I submit and when?
11. §63.1576 What records must I keep, in what form, and for how long?
12. §63.1577 What parts of the General Provisions apply to me?

- b. Per the June 30, 2008 CD, the FCCU is an affected facility under NSPS Subpart J for PM, CO and SO₂, and shall comply with all applicable requirements, including, but not necessarily limited to the following.
 - 1. §60.102 Standard for particulate matter.
 - 2. §60.103 Standard for carbon monoxide.
 - 3. §60.104a Standards for sulfur oxides.
 - 4. §60.105 Monitoring of emissions and operations.
 - 5. §60.106 Test methods and procedures.
 - 6. §60.107 Reporting and recordkeeping requirements.
 - 7. §60.108 Performance test and compliance provisions.
- c. Per the June 30, 2008 CD, the FCCU is an affected facility under NSPS Subpart A (General Requirements) and shall comply with all applicable requirements.
- d. A Selective Catalytic Reduction system shall be operated on the discharges from the FCCU to meet the NO_x emissions limits above.
- e. NO_x and SO₂ emissions and O₂ concentrations shall be monitored continuously using continuous emission monitoring systems which are certified using the procedures of 40 CFR Part 60, Appendix B and F. Records of daily, 7-day rolling average, and 365-day rolling averages shall be kept.
- f. As an alternative to the monitoring requirements for opacity of NSPS Subpart J, an Alternate Monitoring Plan may be implemented as follows as approved by EPA on December 20, 2013:
 - 1. The “Liquid-to-Gas Ratio” (L/G) is the operating parameter defined as total liquid flow through the scrubber (e.g., gallons per minute, gpm) divided by total gas flow through the scrubber (e.g., actual cubic feet per minute, ACFM). Continuous monitoring of L/G will be necessary to determine compliance with two separate limits, the 3-hour rolling average *Minimum L/G*, dependent on the number of nozzles actually operating during that period.
 - A. If only one nozzle is in operation, L/G must be equal to or greater than 0.061 gpm per 1,000 ACFM.
 - B. If two nozzles are in operation, L/G must be equal to or greater than 0.054 gpm per 1,000 ACFM.
 - 2. Excess emissions shall be reported when the *Minimum L/G* is not met, for either of the operating scenarios (i.e., number of nozzles operational).
 - 3. When a periodic demonstration test is conducted in the future, the facility shall establish new limits for *Minimum L/G*, two separate OPLs based on the number of nozzles in actual operation, and submit the new limits with a copy of the test report to the EPA Region VI. Each *Minimum L/G* will be determined from the average of the three values demonstrated during the test series, and are effective upon the date the report is mailed to EPA.
 - 4. In addition, an excess emission will be reported if the 3-hr rolling average L/G at the specified number of operating nozzles falls below the level set during performance testing.

- g. Recordkeeping
 - 1. NSPS Subpart J, MACT Subparts A and UUU, including, but not limited to, CEMs and COMS information, periods of excess emissions, SSM records, performance and RATA tests, and OMM records. [40 CFR 60 Subpart J and 40 CFR 63 Subpart UUU]
- h. Reporting per NSPS Subpart J, MACT Subparts A and UUU, including, but not limited to, semi-annual compliance reports, SSM reports, and CEMs excess emission reports.
[40 CFR 60 Subpart J and 40 CFR 63 Subpart UUU]
- i. Emissions during periods of start-up, shutdown, or malfunction of the FCCU or FCCU emissions control system will not be used in determining compliance with the 7-day average limits for NO_x, CO, or PM.

EUG 12 Flares

Sources in other EUGs under various regulations utilize the flares as air pollution control devices. Monitoring, recordkeeping, and reporting requirements related to flare pilot monitoring are found in each affected EUG, and not included here.

Flare	Make/Model	Height (ft)	Date
#1	Zink/STF-SA-18	230	1949
#2	Zink/STF-SA-36-C	250	1972

- a. The flares are regulated under 40 CFR 60 Subpart A and 40 CFR 63 Subpart A. Requirements include, but are not limited to:
 - 1. General control device requirements [40 CFR 60.18]
 - 2. Control device requirements [40 CFR 63.11]
- b. The flares shall be monitored continuously for the presence of a pilot flame.
[40 CFR 60.18(f)]
- c. The flares are subject to New Source Performance Standards (NSPS), Subpart Ja, and shall comply with all applicable provisions of NSPS, Subpart Ja including but not limited to:
[40 CFR Part 60, Subpart Ja]
 - 1. § 60.102a Emissions limitations;
 - 2. § 60.103a Work practice standards;
 - 3. § 60.104a Performance tests;
 - 4. § 60.107a Monitoring of emissions and operations for process heaters and other fuel gas combustion devices; and
 - 5. § 60.108a Recordkeeping and reporting requirements.
- d. EPA has recognized that periodic maintenance may be required for properly designed and operated flare gas recovery system. The permittee shall take all reasonable measures to minimize emissions while such periodic maintenance is being performed. The Flare Gas Recovery system may be bypassed in the event of an emergency or in order to ensure safe

operation of the refinery process. Nothing in the Consent Decree precludes the permittee from temporarily bypassing a flare gas recovery system under such circumstances. Otherwise, a flare gas recovery system shall be maintained to control continuous or routing combustion [CD]

EUG 13 MACT EEEE Tanks

This EUG contains vessels subject to 40 CFR 63 Subpart EEEE. Because these perchloroethylene tanks are smaller than 5,000 gallons, Subsection 63.2343(a) indicates that these emission sources do not require control.

Tank No.	Location	Year Built	Height	Diameter	Nominal Capacity
10F-163	CCR	2007	4'	8'	18 bbl
4V-31	Unifiner	2002	13.5'	4.5'	30 bbl

EUG 15 High Vapor Pressure Loading Operations

There are several loading racks that handle VOC materials. All units except the propylene racks were “grandfathered” from NSPS and Oklahoma Rules (constructed prior to any applicable rule). No specific emission limits are applied to this EUG under Title V but it is limited to the existing equipment as it is.

Rack	Point ID	Material	Capacity	Date
Butane truck	6171	Butane loading and unloading	4 trucks	1923
Propylene	13404	Propylene loading	2 cars, 2 trucks	Railcars/1996, Trucks/1997

EUG 16 Existing Fugitive Emissions

Equipment leaks from the existing refinery, including but not limited to the process units, storage tanks, and the terminal are included in this Group. There are no emission limits applied to this EUG under Title V but it is limited to the existing equipment as it is. Because all equipment leaks are subject to the LDAR requirements of OAC 252:100-39-15 and some are also subject to LDAR requirements of NSPS Subparts GGG or GGGa, or to the LDAR requirements of MACT CC, the permittee will comply by meeting the following conditions. Under the requirements of the consent decree, all existing units accept NSPS Subpart GGG applicability. Units constructed for the Heavy Crude Processing Expansion project under Permit No. 2007-005-TV (M-1) and the Distillate Hydrotreater Unit, Continuous Catalytic Reformer Unit, Naphtha Splitter Reboiler Unit, and Flare Gas Recovery Unit are subject to NSPS Subpart GGGa. (The Sodium Hydrosulfide (NaSH) Unit will process inorganic materials, therefore, is not subject to NSPS Subpart GGGa.) [40 CFR 60.590, 40 CFR 60.590a, and OAC 252:100-39-15]

- a. All affected equipment, in HAP service (contacting > 5% by weight HAP), shall comply with NESHAP, 40 CFR 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component. [40 CFR 63, Subpart CC]
 1. § 63.642 General Standards – (c), (d)(1), (e), & (f);
 2. § 63.648 Equipment Leak Standards – (a), (b), (c), & (e-i);
 3. § 63.654 Reporting and Recordkeeping Requirements – (d), & (f-h).
- b. Equipment constructed or modified after January 4, 1983, and on or before November 7, 2006, determined not to be in HAP service (contacting < 5% by weight HAP) and which is in VOC service (contacting > 10% by weight VOC) shall comply with the requirements of NSPS 40 CFR 60, Subpart GGG. [40 CFR 60, Subpart GGG]
 1. § 60.592 Standards (a-e).
 2. § 60.593 Exceptions (a-e).
 3. These conditions reference the standards are described in § 60.592 by reference to NSPS Subpart VV §§60.482-1 through 60.482-10. Test methods and procedures, record-keeping, and reporting are described in §§60.485, 486, and 487, respectively.
- c. Equipment constructed or modified after November 7, 2006, determined not to be in HAP service (contacting < 5% by weight HAP) and which is in VOC service (contacting > 10% by weight VOC) shall comply with the requirements of NSPS 40 CFR 60, Subpart GGGa. [40 CFR 60, Subpart GGGa]
 1. § 60.592a Standards (a-e).
 2. § 60.593a Exceptions (a-e).
 3. These conditions reference the standards are described in § 60.592a by reference to NSPS Subpart VVa §§60.482-1a through 60.482-10a. Test methods and procedures, record-keeping, and reporting are described in §§60.485a, 486a, and 487a, respectively.
- d. Certain equipment is regulated as described in OAC 252:100-39-15.
- e. Permittee shall maintain records identifying which components are regulated under each of the requirements listed in a, b, and c preceding.
- f. Recordkeeping provisions for these regulations are very extensive and are not summarized here. Records for components covered by the above requirements are found in the applicable rule. [40 CFR 63.654, 40 CFR 60.486, and OAC 252:100-39-15]
- g. Reporting provisions for these regulations are very extensive and are not summarized here. A single report may be submitted to comply with all of the reporting requirements above, so long as all reporting requirements for each regulation are included. [40 CFR § 63.654, 40 CFR § 60.487, and OAC 252:100-39-15]

EUG 17 Wastewater System

The wastewater system consists of several different sewer systems and the wastewater treatment plant, as described in Part N of Section II (Facility Description) above. The facility is subject to 40 CFR 61 Subpart FF (BWON) and 40 CFR 63 Subpart CC (MACT CC), while areas of the refinery are subject to 40 CFR 60 Subpart QQQ (NSPS QQQ). Due to the overlap regulations under MACT CC (40 CFR 63.640(o)), all Group 1 wastewater streams also regulated under NSPS QQQ must meet only MACT CC standards, while all Group 1 wastewater streams also regulated under BWON must meet only BWON standards. A June 11, 2007, EPA Applicability Determination (AD) issued to BP Products North America and signed by George Czerniak, states that a Group 2 wastewater stream may be treated under BWON exclusively if the facility declares it to be Group 1 and satisfies the requirements of Subpart FF for the stream. Given this AD, the entire SCAN Unit, entire NHDS Unit, and new construction at the DHTU and CCR are subject to BWON. Aggregated emission points are identified as Point ID 13409.

- a. The Refinery is subject to NESHAP, 40 CFR 61, Subpart FF and shall comply with all applicable requirements. [40 CFR 61, NESHAP, Subpart FF]
 1. § 61.342 Standards: General.
 2. § 61.343 Standards: Tanks.
 3. § 61.344 Standards: Surface Impoundments.
 4. § 61.345 Standards: Containers.
 5. § 61.346 Standards: Individual drain systems.
 6. § 61.347 Standards: Oil-water separators.
 7. § 61.348 Standards: Treatment processes.
 8. § 61.349 Standards: Closed-vent systems and control devices.
 9. § 61.350 Standards: Delay of repair.
 10. § 61.351 Alternative standards for tanks.
 11. § 61.352 Alternative standards for oilwater separators.
 12. § 61.353 Alternative means of emission limitation.
 13. § 61.354 Monitoring of operations.
 14. § 61.355 Test methods, procedures, and compliance provisions.
 15. § 61.356 Recordkeeping requirements.
 16. § 61.357 Reporting requirements.
- b. These records will be maintained in accordance with the recordkeeping requirements under 40 CFR § 61.356.
- c. These reports will be maintained in accordance with the reporting requirements under 40 CFR § 61.357.

EUG 18 Hydrocarbon Recovery System

The Hydrocarbon Recovery Tanks, all of which were constructed between 2007 and 2009, are subject to MACT GGGGG. They share a common Point ID of 14487. This EUG has no emission limitation.

Tank No.	Height (feet)	Diameter (feet)	Nominal Capacity
B1	6	3.8	12 bbl
B2	6	3.8	12 bbl
B4	6	3.8	12 bbl
B5	N/A	N/A	55 gallons
B7	6	3.8	12 bbl
B8	6	3.8	12 bbl
B9	6	3.8	12 bbl
B10	6	3.8	12 bbl
B11	6	3.8	12 bbl
B12	6	3.8	12 bbl

- a. Site remediation activities at the refinery are subject to 40 CFR 63 Subpart GGGGG and the refinery shall comply with any applicable requirements including but not limited to:

[40 CFR 63 Subpart GGGGG]

1. § 63.7880 - 7883 What This Subpart Covers
2. § 63.7884 - 7888 General Standards
3. § 63.7890 - 7893 Process Vents
4. § 63.7895 - 7898 Tanks
5. § 63.7900 - 7903 Containers
6. § 63.7920 - 7922 Equipment Leaks
7. § 63.7935 - 7938 General Compliance Requirements
8. § 63.7950 - 7953 Notifications, Reports, and Recordkeeping
9. § 63.7955 - 7957 Other Requirements and Information
10. The permittee shall comply with the provisions of 40 CFR 63 Subpart A as specified in Appendix to Subpart GGGGG, Table 3.

EUG 19 Cooling Towers

Number	Point ID	Purpose	Date
3	25053	Cooling water for the FCCU	1949
3a	25054	Cooling water for SCANfiner	2003
4 and 5	25055	Cooling water for the CDU	1949
7	25056	Cooling water for the ALKY, POLY & ISOM	2007*
8	25057	Cooling water for the OIF	1972
7a	25056a	Cooling water for the ALKY, POLY & ISOM	2012

* Replaced tower built in 1949.

- a. These cooling towers shall comply with 40 CFR 63.654 and 40 CFR 63.655 upon the effective compliance date.

EUG 20 NSPS Kb Tank (EFR) - MACT CC Group 1 Wastewater

These storage vessels are regulated under 40 CFR 60, Subpart Kb and are limited to the existing equipment as it is. Due to the overlap provisions of MACT CC, the vessels are required to comply only with Kb, except as noted in 40 CFR § 63.640(n)(8).

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
476	36590	2005	45'	55'	15,000
478	N/A	2014	59	102	100,000
477	N/A	2006	40'	30'	5,000
474	15940	1997	48'	106'	73,000
475	15941	1997	48'	106'	73,000

- a. The EFR tank in EUG 20 is subject to NSPS Subpart Kb. The “overlap” provisions of MACT CC [§ 63.640(n)(1)] state that these storage vessels are required only to comply with the provisions of Kb, with the modifications noted in § 63.640(n)(8).

1. Mechanical design and operating specifications. [40 CFR § 60.112b(a)(2)]
2. Compliance testing and procedures. [40 CFR § 60.113b(b)]
3. Monitoring provisions [40 CFR § 60.116b]

- b. Tanks in this EUG may be used in MACT CC Group 1 wastewater service as they comply with the Alternative Standards for Storage Tanks of 40 CFR § 61.351 and 40 CFR 60 Subpart Kb.

- c. The sliding cover shall be in place over the slotted-guidepole opening through the floating roof at all times except when the sliding cover must be removed for access. Visually inspect the deck fitting for the slotted guidepole at least once every 10 years and each time the vessel is emptied and degassed. If the slotted guidepole deck fitting or control device(s) have defects, or if a gap or more than 0.32 centimeters (1/8 inch) exists between any gasket required for control of the slotted guidepole deck fitting and any surface that it is intended to seal, such items shall be repaired before filling or refilling the storage vessel with regulated material. Tanks out of hydrocarbon service, for any reason, do not have to have any controls in place during the time they are out of service.

[EPA’s Storage Tank Emission Reduction Partnership Agreement]

- d. Recordkeeping requirements include:

1. Inspection results, dimensions and capacity of the storage vessels, VOL stored, period of storage, and maximum TVP. [40 CFR § 60.115b and 116b]

- e. Reporting requirements include semi-annual reporting of deviations during inspections, notifications, and initial certifications. [40 CFR § 60.115b and 63.640(n)(8)(v)]

EUG 21 Pressurized Spheres

These units are “grandfathered” (constructed prior to any applicable rule). There are no emission limits applied to this EUG under Title V but it is limited to the existing equipment as it is. Because there are no measurable emissions from any of these tanks, they are all classified as Insignificant.

Tank No.	Point ID	Year Built	Diameter (feet)	Nominal Capacity (bbls)
207	6281	1948	48	9,250
208	6282	1924	48	9,250
218	6284	1986	55	13,750
219	6285	1986	55	13,750
220	6286	1953	51	10,800
221	6287	1953	51	10,800

EUG 22 Pressurized Bullet Tanks

Because there are no measurable emissions from these tanks, they are all classified as Insignificant.

Tank No.	Point ID	Year Built	Length (feet)	Diameter (feet)	Nominal Capacity (bbls)
58	6288	1960	66	12	1,300
59	6289	1960	66	12	1,300
60	6290	1960	66	12	1,300
64	6291	1967	84	10	1,300
65	6292	1967	84	10	1,300
66	6293	1967	84	10	1,300
70	6294	1979	70	11	1,000
71	6295	1979	70	11	1,000
72	6296	1998	78	10	1,000
73	6297	1998	78	10	1,000

EUG 23 MACT CC Group 2 Wastewater Tanks

These tanks are affected facilities under MACT CC, but there are no standards or requirements under CC. Therefore, the only requirements are those of NESHAP Subpart FF.

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
52	22638	1972	36'	40'	7,500
56	36193	1992	16'	25'	1,400
57	36193	1992	16'	25'	1,400
140	23134	1971	16'	36'	2,900
369	23134	1960	23'	12'	480

EUG 24 Tanks Subject to NESHAP FF

The following tank is subject to the benzene waste organic NESHAP, but is too small to be an affected facility under the Refinery MACT.

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
67	23134	1992	12'	10'	165

EUG 25 Fuel-Burning Equipment with Heat Input < 100MMBTUH

This EUG contains new fuel-burning equipment with heat input less than 100 MMBTUH. These sources are subject to regulation under 40 CFR 63 Subpart DDDDD (MACT DDDDD).

Source	Point ID	Manufacturer	Burner Type	No. of Burners	MMBTUH (HHV)	Const. Date	NO _x lb/MMBTU (HHV)
Scanfiner Charge (12H-101)	23133	Tulsa Heaters, Inc	ZeeCo New Gen Low NO _x	3	25.2	2004	0.07
NHDS Charge (02H-001)	36580	Tulsa Heaters, Inc	ZeeCo Low NO _x	4	39	2006	0.05
NHDS Stripper Reboiler (02H-002)	36584	Tulsa Heaters, Inc	ZeeCo Next Gen Low NO _x	6	44.2	2006	0.05

- a. Compliance with the SO₂ limits is demonstrated by compliance with the H₂S limit imposed on fuel gas combustion devices by NSPS Subpart J and fuel input. Compliance with the fuel input limits will be calculated by using the monthly fuel input to calculate hourly average heat input. [40 CFR 60, Subpart J and OAC 252:100-43]
- b. Compliance with the NO_x limits is demonstrated by performance testing of the low-NO_x burners. Compliance with these limits is demonstrated by heat input to each unit, using monthly fuel inputs to calculate hourly averages. [OAC 252:100-43]

- c. All heaters must comply with 40 CFR 60 Subpart J, and shall comply with all applicable provisions including but not limited to: [40 CFR 60, Subpart J and OAC 252:100-43]
1. § 60.104 Standards for sulfur dioxide – (a)(1)
 2. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
 3. § 60.106 Test methods and procedures – (e)
- d. Compliance with the H₂S destruction efficiency criterion and H₂S emission limitation of OAC 252:100-31-25 concerning the SCANfiner process unit shall be demonstrated using the SRU CEMS or through engineering calculations and judgment. [OAC 252:100-31]
- e. Recordkeeping is required as follows:
1. NSPS J records as required under 40 CFR 60 Subpart A. [40 CFR 60.7]
 2. H₂S CEM to show compliance with SO₂ emission limits for specified heaters. [OAC 252:100-43]
 3. NO_x performance tests for specified heaters. [OAC 252:100-43]
 4. Monthly fuel use for each piece of fuel-burning equipment in EUG 25 with a heat input limit shall be maintained, along with a calculation demonstrating that the average hourly firing rate of each item is not greater than the heat rate set forth in SC #1. These records shall be maintained on a 12-month rolling basis. [OAC 252:100-43]
- f. Reporting is required for NSPS Subpart J heaters on a semi-annual basis, including the information required in NSPS Subpart A. [40 CFR 60.107 and 60.7]
- g. The sulfur content of gas fuel in fuel-burning equipment shall not exceed 60 ppm, annual average. The sulfur content shall be monitored using a CEMS which complies with NSPS, Subpart Ja. Records of monitoring results shall be kept. [OAC 252:100-8-6(a)]

EUG 26 Modified Fuel-Burning Equipment with Heat Input ≥ 100MMBTUH

These sources are all regulated under NSPS Ja and 40 CFR 63 Subpart DDDDD (MACT DDDDD).

Source	Point ID	Manufacturer	Burner Type	No. of Burners	MMBTUH (HHV)	Const. Date	NO _x lb/MMBTU (HHV)
CCR #1 Interheater (10H-113)	39225	Tulsa Heaters, Inc	ZeeCo, Inc.	18	155	2005	0.05

- a. Compliance with the SO₂ limit is demonstrated by compliance with the H₂S limit imposed on fuel gas combustion devices by NSPS Subpart Ja and fuel input. Compliance with the fuel input limits will be calculated by using the monthly fuel input to calculate hourly average heat input. [40 CFR 60, Subpart Ja and OAC 252:100-43]
- b. Compliance with the NO_x limit is demonstrated by performance testing of the low-NO_x burners. Compliance with these limits is demonstrated by heat input to each unit, using monthly fuel inputs to calculate hourly averages. [OAC 252:100-43]

- c. All heaters must comply with 40 CFR 60 Subpart Ja, and shall comply with all applicable provisions including but not limited to: [40 CFR 60, Subpart Ja and OAC 252:100-43]
1. § 60.104a Standards for sulfur dioxide – (a)(1).
 2. § 60.105a Monitoring of operations – (a)(4), (e)(3)(ii).
 3. § 60.106 a Test methods and procedures – (e).
- d. Recordkeeping is required as follows:
1. NSPS Ja records as required under 40 CFR 60 Subpart A. [40 CFR 60.7]
 2. H₂S CEM to show compliance with SO₂ emission limits for specified heaters. [OAC 252:100-43-4]
 3. NO_x performance tests for specified heaters. [OAC 252:100-43-3]
 4. Monthly fuel use for each piece of fuel-burning equipment with a heat input limit shall be maintained, along with a calculation demonstrating that the average hourly firing rate of each item is not greater than the heat rate set forth in SC #1. These records shall be maintained on a 12-month rolling basis. [OAC 252:100-43-7]
- e. Reporting is required for NSPS Subpart Ja heaters on a semi-annual basis, including the information required in NSPS Subpart A. [40 CFR 60.107 and 60.7]
- f. The sulfur content of gas fuel in fuel-burning equipment shall not exceed 60 ppm, annual average. The sulfur content shall be monitored using a CEMS which complies with NSPS, Subpart Ja. Records of monitoring results shall be kept. [OAC 252:100-8-6(a)]

EUG 27 Existing Fuel-Burning Equipment Accepting NO_x Limits

The following table shows available information for certain heaters.

Source	Point ID	Manu-facturer	Burner Type	No. of Burners	MMBTUH (HHV)	Heater Date	NO _x lb/MMBTU (HHV)
DHTU Reactor Charge 1H-101	6156	Foster-Wheeler	JZ-LOF-27-30	16	55	1972	0.20
CCR Charge Heater 10H-101	6163	SELAS	JZ MA-20	12	120	1972*	0.05
CCR Inter-heater #2-1 10H-102	6163	SELAS	Callidus CRG-LN-8P	8	101	1972	0.20
CCR Interheater #2-2 10H-103	6163	SELAS	JZ MA-22	2	25	1972	0.20
CCR Stabilizer Reboiler 10H-104	6162	SELAS	JZ MA-20	8	85	1972*	0.05
Naphtha Splitter Reboiler	6162	Zeeco	GLSF Free Jet	--	75	1972	0.04

* low-NO_x burners installed in 2005.

**Low-NO_x burners installed in 2011.

- a. Compliance with the NO_x limits is demonstrated by performance testing of the low-NO_x burners. Compliance with these limits is demonstrated by heat input to each unit, using monthly fuel inputs to calculate hourly averages.
- b. CCR Charge Heater 10H-101, CCR Interheater #2-1 10H-102, and CCR Interheater #2-2 10H-103. For performance testing when all three units are operating, a combined limit of 0.13 lb/MMBTU NO_x shall apply. Total NO_x from the three heaters shall not exceed 136.7 TPY.
- c. Monthly fuel use for each piece of fuel-burning equipment with a heat input limit shall be maintained, along with a calculation demonstrating that the average hourly firing rate of each item is not greater than the heat rate set forth in SC #1. These records shall be maintained on a 12-month rolling basis. [OAC 252:100-43-7]
- d. Testing of NO_x emissions (lb/MMBTU) shall be conducted using EPA Methods 7E and 3 or 3A at least once a year for the next five years on each of the above heaters. Emissions of NO_x as reported in annual Emissions Inventories and records as required for "EUG Plantwide" shall be no lower than testing results. [OAC 252:100-43]
- e. Per the CD 08CV 020-D, these heaters are affected facilities under NSPS Subpart J and shall comply with all applicable requirements, including, but not necessarily limited to the following.
 1. §60.104 Standards for sulfur oxides. The CD requires compliance no later than December 31, 2010.
 2. §60.105 Monitoring of emissions and operations.
 3. §60.106 Test methods and procedures.
 4. §60.107 Reporting and recordkeeping requirements.
 5. §60.108 Performance test and compliance provisions.
- f. The sulfur content of gas fuel in fuel-burning equipment shall not exceed 60 ppm, annual average. The sulfur content shall be monitored using a CEMS which complies with NSPS, Subpart Ja. Records of monitoring results shall be kept. [OAC 252:100-8-6(a)]

EUG-28 LPG Unit Fugitive VOC Leakage

EU	Point	Equipment	Estimated Number of Items	Installed Date
LPG	N/A	Fugitive VOC Leakage Components at LPG Recovery Unit	150 gas/vapor valves	2014 - 2015
			150 light liquid valves	
			5 heavy liquid valves	
			660 flanges	
			8 light liquid pumps	
			2 heavy liquid pumps	
			15 gas relief valves	

- a. The above process units are subject to NSPS Subpart GGGa and shall comply with all applicable requirements for leak detection and repair. [40 CFR 60.592(a)]
- b. The owner operator shall comply with the requirements of §§ 60.482-1a through § 60.482-11a except as provided in § 60.593a:
 1. The operator shall demonstrate compliance with §§ 60.482-1a through 60.482-10a for all affected equipment within 180 days of initial startup which shall be determined by review of records, reports, performance test results, and inspection using methods and procedures specified in § 60.485a unless the equipment is in vacuum service and is identified as required by § 60.486a(e)(5). [§ 60.482-1a(a), (b), & (d)]
 2. The owner or operator shall comply with the monitoring, inspection, and repair requirements, for pumps in light liquid service, of §§ 60.482-2a(a), (b), and (c) except as provided in §§ 60.482-2a(d), (e), and (f).
 3. Compressors in hydrogen service are exempt from the requirements of § 60.592a if an owner or operator demonstrates that a compressor is in hydrogen service. [§ 60.593a(b)(1)]
 4. The owner or operator shall comply with the operation and monitoring requirements, for pressure relief devices in gas/vapor service, of §§ 60.482-4a(a) and (b) except as provided in § 60.482-4a(c) and (d).
 5. The owner or operator shall comply with the applicable standards of § 60.482-5a for sampling connection systems.
 6. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall be closed at all other times. [§ 60.482-6a]
 7. The owner operator shall comply with the monitoring, inspection, and repair requirements, for valves in gas/vapor service and light liquid service, of §§ 60.482-7a(b) through (e), except as provided in § 60.482-7a(f), (g), and (h), §§ 60.483-1a, 60.483-2a, and 60.482-1a(c). [§ 60.482-7a(a)]
 8. The owner operator shall comply with the monitoring and repair requirements, or pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors, of §§ 60.482-8a(a) through (d). [§ 60.482-8a]
 9. Delay of repair of equipment is allowed if it meets one of the requirements of §§ 60.482-9a(a) through (e).
 10. The owner or operator using a closed vent system and control device to comply with these provisions shall comply with the design, operation, monitoring and other requirements of §§ 60.482-10a(b) through (m). [§ 60.482-10a(a)]
 11. The owner or operator shall comply with the applicable standards of § 60.482-11a for connectors in gas/vapor service and in light liquid service.
 12. An owner or operator may elect to comply with the alternative requirements for valves of §§ 60.483-1a and 60.483-2a. [§ 60.592a(b) & § 60.482-1a(b)]
 13. Each owner or operator subject to the provisions of NSPS Subpart GGGa shall comply with the test method and procedures of § 60.485a except as provided in §§ 60.593a. [§ 60.592a(d)]

14. Each owner or operator subject to the provisions of NSPS Subpart GGGa shall comply with the recordkeeping requirements of § 60.486a and the reporting requirements of § 60.487a. [§ 60.592a(e)]

EUG-29 New Heaters

Point ID	Emission Unit	PM ₁₀		SO ₂		NO _x		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
ROSE	ROSE Unit Heater	0.32	1.38	1.09	1.80	1.26	5.52	0.21	0.92	1.68	7.36
DHTU	DHTU Helper Heater	0.38	1.64	1.30	2.15	1.50	6.57	0.25	1.10	2.00	8.76
NHDS	NHDS Helper Heater	0.08	0.33	0.26	0.43	0.30	1.31	0.05	0.22	0.40	1.75
CCR	CCR Helper Heater	0.19	0.82	0.65	1.07	0.75	3.28	0.12	0.55	1.00	4.38

- a. The above new combustion units shall comply with all applicable provisions of NSPS, Subpart Ja including but not limited to: [40 CFR Part 60, Subpart Ja]
 1. § 60.102a Emissions limitations;
 2. § 60.103a Work practice standards;
 3. § 60.104a Performance tests;
 4. § 60.107a Monitoring of emissions and operations for process heaters and other fuel gas combustion devices; and
 5. § 60.108a Recordkeeping and reporting requirements.
- b. The above units shall be fueled with refinery fuel gas or pipeline-grade natural gas only. [OAC 252:100-8-6(a)(1) and OAC 252:100-31]
- c. NO_x emissions from each above heater shall not exceed 0.03 lb/MMBTU, expressed as NO₂. CO emissions shall not exceed 0.04 lb/MMBTU. CO₂e emissions shall not exceed 146 lb/MMBTU. PM emissions shall not exceed 0.0076 lb/MMBTU. [OAC 252:100-8-6(a)(1)]
- d. Performance testing as required by 40 CFR Part 60.8 shall be conducted within 60 days of achieving maximum production rate, not to exceed 180 days from initial start-up. [40 CFR 60.8]

EUG-30 ROSE Unit Fugitive Leaks

EU	Point	Equipment	Estimated Number of Items	Installed Date
ROSE	N/A	Fugitive VOC Leakage Components at ROSE Unit	200 gas/vapor valves	2014 - 2015
			300 light liquid valves	
			70 heavy liquid valves	
			1,204 flanges	
			10 light liquid pumps	
			5 heavy liquid pumps	
			2 compressor seals	
			15 gas relief valves	

- a. The above process units are subject to NSPS Subpart GGGa and shall comply with all applicable requirements for leak detection and repair. [40 CFR § 60.592(a)]

- b. The owner operator shall comply with the requirements of §§ 60.482-1a through § 60.482-11a except as provided in § 60.593a:
1. The operator shall demonstrate compliance with §§ 60.482-1a to 60.482-10a for all affected equipment within 180 days of initial startup which shall be determined by review of records, reports, performance test results, and inspection using methods and procedures specified in § 60.485a unless the equipment is in vacuum service and is identified as required by § 60.486a(e)(5). [§ 60.482-1a(a), (b), & (d)]
 2. The owner or operator shall comply with the monitoring, inspection, and repair requirements, for pumps in light liquid service, of §§ 60.482-2a(a), (b), and (c) except as provided in §§ 60.482-2a(d), (e), and (f).
 3. Compressors in hydrogen service are exempt from the requirements of § 60.592a if an owner or operator demonstrates that a compressor is in hydrogen service.
[§ 60.593a(b)(1)]
 4. The owner or operator shall comply with the operation and monitoring requirements, for pressure relief devices in gas/vapor service, of §§ 60.482-4a(a) and (b) except as provided in § 60.482-4a(c) and (d).
 5. The owner or operator shall comply with the applicable standards of § 60.482-5a for sampling connection systems.
 6. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall be closed at all other times. [§ 60.482-6a]
 7. The owner operator shall comply with the monitoring, inspection, and repair requirements, for valves in gas/vapor service and light liquid service, of §§ 60.482-7a(b) through (e), except as provided in §§ 60.482-7a(f), (g), and (h), §§ 60.483-1a, § 60.483-2a, and §60.482-1a(c). [§ 60.482-7a(a)]
 8. The owner operator shall comply with the monitoring and repair requirements, or pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors, of §§ 60.482-8a(a) through (d). [§ 60.482-8a]
 9. Delay of repair of equipment is allowed if it meets one of the requirements of §§60.482-9a(a) through (e).
 10. The owner or operator using a closed vent system and control device to comply with these provisions shall comply with the design, operation, monitoring and other requirements of §60.482-10a(b) through (m). [§ 60.482-10a(a)]
 11. The owner or operator shall comply with the applicable standards of § 60.482-11a for connectors in gas/vapor service and in light liquid service.
 12. An owner or operator may elect to comply with the alternative requirements for valves of §§ 60.483-1a and 60.483-2a. [§ 60.592a(b) & § 60.482-1a(b)]
 13. Each owner or operator subject to the provisions of NSPS Subpart GGGa shall comply with the test method and procedures of § 60.485a except as provided in §§ 60.593a.
[§ 60.592a(d)]
 14. Each owner or operator subject to the provisions of NSPS Subpart GGGa shall comply with the recordkeeping requirements of § 60.486a and the reporting requirements of § 60.487a.
[§ 60.592a(e)]

EUG 32: DHTU, NHDS Unit, Alky Unit, FCCU Regenerator Unit, and Naphtha Fractionation Column Fugitive VOC Leaks

EU	Point	Equipment	Estimated Number of Items	Installed Date
DHTU	N/A	Fugitive VOC Leakage Components at DHTU Unit	20 gas/vapor valves	2014 - 2015
			45 light liquid valves	
			2 light liquid pumps	
			144 flanges	
			5 gas relief valves	
NHDS	N/A	Fugitive VOC Leakage Components at NHDS Unit	20 gas/vapor valves	2014 - 2015
			45 light liquid valves	
			2 light liquid pumps	
			144 flanges	
			5 gas relief valves	
Alky	N/A	Fugitive VOC Leakage Components at Alky Unit	20 gas/vapor valves	2014 - 2015
			45 light liquid valves	
			2 light liquid pumps	
			144 flanges	
			5 gas relief valves	
FCCU Regenerator	N/A	Fugitive VOC Leakage Components at FCCU Regenerator Unit	50 gas/vapor valves	2014 - 2015
			75 light liquid valves	
			3 light liquid pumps	
			268 flanges	
			6 gas relief valves	
Naphtha Fractionation	N/A	Fugitive VOC Leakage Components at Naphtha Fractionation Column Unit	125 gas/vapor valves	2014 - 2015
			125 light liquid valves	
			3 light liquid pumps	
			524 flanges	
			1 compressor seal	
			8 gas relief valves	

- a. The above process units are subject to NSPS Subpart GGGa and shall comply with all applicable requirements for leak detection and repair. [40 CFR § 60.592(a)]
- b. The owner operator shall comply with the requirements of §§ 60.482-1a through § 60.482-11a except as provided in § 60.593a:
 1. The operator shall demonstrate compliance with §§ 60.482-1a to 60.482-10a for all affected equipment within 180 days of initial startup which shall be determined by review of records, reports, performance test results, and inspection using methods and procedures specified in § 60.485a unless the equipment is in vacuum service and is identified as required by § 60.486a(e)(5). [§ 60.482-1a(a), (b), & (d)]
 2. The owner or operator shall comply with the monitoring, inspection, and repair requirements, for pumps in light liquid service, of §§ 60.482-2a(a), (b), and (c) except as provided in §§ 60.482-2a(d), (e), and (f).
 3. Compressors in hydrogen service are exempt from the requirements of § 60.592a if an owner or operator demonstrates that a compressor is in hydrogen service.

[§ 60.593a(b)(1)]

4. The owner or operator shall comply with the operation and monitoring requirements, for pressure relief devices in gas/vapor service, of §§ 60.482-4a(a) and (b) except as provided in § 60.482-4a(c) and (d).
5. The owner or operator shall comply with the applicable standards of § 60.482-5a for sampling connection systems.
6. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall be closed at all other times. [§ 60.482-6a]
7. The owner operator shall comply with the monitoring, inspection, and repair requirements, for valves in gas/vapor service and light liquid service, of §§ 60.482-7a(b) through (e), except as provided in 60.482-7a(f), (g), and (h), §§ 60.483-1a, 60.483-2a, and 60.482-1a(c). [§ 60.482-7a(a)]
8. The owner operator shall comply with the monitoring and repair requirements, or pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors, of §§ 60.482-8a(a) through (d). [§ 60.482-8a]
9. Delay of repair of equipment is allowed if it meets one of the requirements of §§60.482-9a(a) through (e).
10. The owner or operator using a closed vent system and control device to comply with these provisions shall comply with the design, operation, monitoring and other requirements of 60.482-10a(b) through (m). [§ 60.482-10a(a)]
11. The owner or operator shall comply with the applicable standards of § 60.482-11a for connectors in gas/vapor service and in light liquid service.
12. An owner or operator may elect to comply with the alternative requirements for valves of §§ 60.483-1a and 60.483-2a. [§ 60.592a(b) & § 60.482-1a(b)]
13. Each owner or operator subject to the provisions of NSPS Subpart GGGa shall comply with the test method and procedures of § 60.485a except as provided in §§ 60.593a. [§ 60.592a(d)]
14. Each owner or operator subject to the provisions of NSPS Subpart GGGa shall comply with the recordkeeping requirements of § 60.486a and the reporting requirements of § 60.487a. [§ 60.592a(e)]

EUG-33 Modified CDU Heater

Point ID	Emission Unit	PM ₁₀		SO ₂		NO _x		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
6155	CDU Atmospheric Tower Heater	1.86	8.15	6.45	10.65	7.44	32.59	1.34	5.87	9.92	43.45

- a. The above combustion unit shall comply with all applicable provisions of NSPS, Subpart Ja including but not limited to: [40 CFR Part 60, Subpart Ja]
 1. § 60.102a Emissions limitations;

2. § 60.103a Work practice standards;
 3. § 60.104a Performance tests;
 4. § 60.107a Monitoring of emissions and operations for process heaters and other fuel gas combustion devices; and
 5. § 60.108a Recordkeeping and reporting requirements.
- b. The unit shall be fueled with refinery fuel gas or pipeline-grade natural gas only.
[OAC 252:100-8-6(a)(1) and OAC 252:100-31]
- c. NO_x emissions from each above heater shall not exceed 0.03 lb/MMBTU, expressed as NO₂. CO emissions shall not exceed 0.04 lb/MMBTU. CO_{2e} emissions shall not exceed 146 lb/MMBTU. PM emissions shall not exceed 0.0076 lb/MMBTU. [OAC 252:100-8-6(a)(1)]
- d. Performance testing as required by 40 CFR Part 60.8 shall be conducted within 60 days of achieving maximum production rate, not to exceed 180 days from initial start-up following modifications. [40 CFR 60.8]

EUG 34 Stationary Engines Subject to 40 CFR Part 63 Subpart ZZZZ

ID Number	HP	Description	Construction/ Modification Date
007-J-26G	75	Kohler 50RZB 4SRB emergency engine	2004
008-PA-50	75	Kohler 50RZGB-051 4SRB emergency engine	2003
050-G-1M	66	Kohler 20RZ-Q5 4SRB emergency engine	2002
004-G-1	104	Kohler 304Z-QS 4SRB emergency engine	2001
012-G-1M	421	Kohler 275RZD 4SRB emergency engine	2004

- a. The owner/operator shall comply with all applicable requirements of the NESHAP for Stationary Reciprocating Internal Combustion Engines (RICE), Subpart ZZZZ, for the above emergency engines, including but not limited to: [40 CFR 60.630 to 60.636]
1. § 63.6580 What is the purpose of subpart ZZZZ?
 2. § 63.6585 Am I subject to this subpart?
 3. § 63.6590 What parts of my plant does this subpart cover?
 4. § 63.6595 When do I have to comply with this subpart?
 5. § 63.6600 What emission limitations and operating limitations must I meet?
 6. § 63.6605 What are my general requirements for complying with this subpart?
 7. § 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations?
 8. § 63.6615 When must I conduct subsequent performance tests?
 9. § 63.6620 What performance tests and other procedures must I use?
 10. § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?
 11. § 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?
 12. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

13. § 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?
14. § 63.6645 What notifications must I submit and when?
15. § 63.6650 What reports must I submit and when?
16. § 63.6655 What records must I keep?
17. § 63.6660 In what form and how long must I keep my records?
18. § 63.6665 What parts of the General Provisions apply to me?
19. § 63.6670 Who implements and enforces this subpart?
20. § 63.6675 What definitions apply to this subpart?

EUG 34a Stationary Engines Subject to 40 CFR Part 60 Subpart JJJJ

ID Number	HP	Description	Construction/ Modification Date
045-G-1M	360	Kohler 275 RZDB 4SRB emergency engine	2010
006-PE-80M	45	Kohler 25RZGB 4SRB emergency engine	2008

- a. The above engines are subject to 40 CFR Part 60, Subpart JJJJ, and shall comply with all applicable standards for owners or operators of stationary spark ignition internal combustion engines:
 1. 60.4230: Am I subject to this subpart?
 2. 60.4231: What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines?
 3. 60.4232: How long must my engines meet the emissions standards if I am a manufacturer of stationary SI internal combustion engines?
 4. 60.4233: What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?
 5. 60.4234: How long must I meet the emissions standards if I am an owner or operator of a stationary SI internal combustion engine?
 6. 60.4235: What fuel requirements must I meet if I am an owner or operator of a stationary SI internal combustion engine?
 7. 60.4236: What is the deadline for importing or installing stationary SI ICE produced in the previous model year?
 8. 60.4237: What are the monitoring requirements if I am an owner or operator of a stationary SI internal combustion engine?
 9. 60.4238: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines \leq 19 KW (25 HP).
 10. 60.4239: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines \geq 19 KW (25 HP) that use gasoline?
 11. 60.4240: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines \geq 19 KW (25 HP) that use LPG?
 12. 60.4241: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program?
 13. 60.4242: What other requirement must I meet if I am a manufacturer of stationary SI internal combustion engines?

14. 60.4243: What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?
15. 60.4244: What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?
16. 60.4245: What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?
17. 60.4246: What parts of the General Provisions apply to me?
18. 60.4247: What parts of the mobile source provisions apply to me if I am a manufacturer of stationary SI internal combustion engines?
19. 60.4248: What definitions apply to this subpart?

EUG 35 Stationary Engines Subject to 40 CFR Part 63 Subpart ZZZZ

ID Number	HP	Description	Construction/ Modification Date
009-PE-143	700	Cummins VT-1710-F CI emergency engine	1977
009-PE-144	262	John Deere 6081HF001 CI emergency engine	Pre-2002

- a. The owner/operator shall comply with all applicable requirements of the NESHAP for Stationary Reciprocating Internal Combustion Engines (RICE), Subpart ZZZZ, for the above emergency engines, including but not limited to: [40 CFR 60.630 to 60.636]
 1. § 63.6580 What is the purpose of subpart ZZZZ?
 2. § 63.6585 Am I subject to this subpart?
 3. § 63.6590 What parts of my plant does this subpart cover?
 4. § 63.6595 When do I have to comply with this subpart?
 5. § 63.6600 What emission limitations and operating limitations must I meet?
 6. § 63.6605 What are my general requirements for complying with this subpart?
 7. § 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations?
 8. § 63.6615 When must I conduct subsequent performance tests?
 9. § 63.6620 What performance tests and other procedures must I use?
 10. § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?
 11. § 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?
 12. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?
 13. § 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?
 14. § 63.6645 What notifications must I submit and when?
 15. § 63.6650 What reports must I submit and when?
 16. § 63.6655 What records must I keep?
 17. § 63.6660 In what form and how long must I keep my records?
 18. § 63.6665 What parts of the General Provisions apply to me?
 19. § 63.6670 Who implements and enforces this subpart?
 20. § 63.6675 What definitions apply to this subpart?

EUG 35a Stationary Engines Subject to 40 CFR Part 60 Subpart IIII

ID Number	HP	Description	Construction/ Modification Date
033-EG-5320	700	Caterpillar C18 214-0021 CI emergency engine	2010
009-PE-152	380	Cummins CFP15E-F10 CI emergency engine	2014

- a. The above engines are subject to 40 CFR Part 60, Subpart IIII, and shall comply with all applicable requirements: [40 CFR 60.4200 – 4219]

1. 60.4200: Am I subject to this subpart?
2. 60.4201: What emissions standards must I meet for non-emergency engines if I am a stationary CI engine manufacturer?
3. 60.4202: What emissions standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacture?
4. 60.4203: How long must my engines meet the emissions standards if I am a stationary CI internal combustion engine manufacturer?
5. 60.4204: What emissions standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
6. 60.4205: What emissions standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
7. 60.4206: How long must my engines meet the emissions standards if I am a owner or operator of a stationary CI internal combustion engine?
8. 60.4207: What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?
9. 60.4208: What is the deadline for importing or installing stationary CI ICE produced in the previous model year?
10. 60.4209: What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?
11. 60.4210: What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?
12. 60.4211: What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?
13. 60.4212: What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?
14. 60.4213: What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?
15. 60.4214: What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?
16. 60.4215: What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?
17. 60.4216: What requirements must I meet for engines used in Alaska?
18. 60.4217: What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

19. 60.4218: What parts of the General Provisions apply to me?

Insignificant Activities

Various records shall be maintained to demonstrate the continued status of certain emission sources as Insignificant Activities, as follow. [OAC 252:100-43]

1. The amount of fuel dispensed from tanks #419 and #420 (monthly).
2. Vapor pressure for any tanks satisfying the criteria of capacity less than 39,894 gallons and storing a liquid with vapor pressure less than 1.5 psia (annual maximum).
3. Number of drums no larger than 55 gallons and containing less than 3% by volume of residual material, washed and/or crushed (annual).
4. Total emissions from any source classified as Insignificant on the basis of its emissions (annual), as well as a description of the calculation method used and data used in the calculation.

EUG Plant-wide Miscellaneous

- a. Certain equipment within the refinery is subject to 40 CFR 63 Subpart CC and all affected equipment shall comply with all applicable requirements. Requirements listed in previous EUGs are not repeated here. [40 CFR 63 Subpart CC]
 1. § 63.642 General Standards
 2. § 63.643 Miscellaneous Process Vent Provisions
 3. § 63.644 Monitoring for Miscellaneous Process Vents
 4. § 63.645 Test Methods and Procedures for Miscellaneous Process Vents
 5. § 63.654 Reporting and Recordkeeping Requirements
 6. The permittee shall comply with the provisions of 40 CFR 63 Subpart A as specified in Appendix to Subpart CC, Table 6.
- b. Various asbestos renovation and demolition projects at the Tulsa Refinery are subject to State and Federal standards, including:
 1. The federal standards found in 40 CFR 61 Subpart M. [40 CFR § 61.145]
 2. The following requirements for handling asbestos are in addition to those listed in the asbestos NESHAP, 40 CFR 61 Subpart M. [OAC 252:100-40-5]
 - A. Before being handled, stored or transported in or to the outside air, friable asbestos from demolition/renovation operations shall be double bagged in six-mil plastic bags, or single bagged in one six-mil plastic bag and placed in a disposable drum, or contained in any other manner approved in advance by the AQD Director.
 - B. When demolition/renovation operations must take place in the outdoor air, friable asbestos removed in such operations shall be immediately bagged or contained in accordance with (A).

- C. Friable asbestos materials used on pipes or other outdoor structures shall not be allowed to weather or deteriorate and become exposed to, or dispersed in the outside air.
 - D. Friable asbestos materials shall, in addition to other provisions concerning disposal, be disposed of in a facility approved for asbestos by the Solid Waste Management Division of DEQ.
- c. The following procedures are required for any process unit shutdown, purging, or blowdown operation. [OAC 252:100-39-16]
- 1. Recovery of VOC shall be accomplished during the shutdown or turnaround to a process unit pressure compatible with the flare or vapor system pressure. The unit shall then be purged or flushed to a flare or vapor recovery system using a suitable material such as steam, water or nitrogen. The unit shall not be vented to the atmosphere until pressure is reduced to less than 5 psig through control devices.
 - 2. Except where inconsistent with the "Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline," or any State of Oklahoma regulatory agency, no person shall emit VOC gases to the atmosphere from a vapor recovery blowdown system unless these gases are burned by smokeless flares or an equally effective control device as approved by the Division Director.
 - 3. At least fifteen days prior to a scheduled turnaround, a written notification shall be submitted to the Division Director. As a minimum, the notification shall indicate the unit to be shutdown, the date of shutdown, and the approximate quantity of VOC to be emitted to the atmosphere.
 - 4. Scheduled refinery unit turnaround may be accomplished without the controls specified in (a) and (b) during non-oxidant seasons provided the notification to the Division Director as required in (c) specifically contains a request for such an exemption. The non-oxidant season is from November 1 through March 31.
- d. Non-condensable VOC from surface condensers and accumulators in the CDU vacuum producing system shall be vented to a heater firebox. [OAC 252:100-39-17]
- e. Cold metal-cleaning units using any VOC shall comply with the following requirements.
- 1. Mechanical design. The unit shall have a cover or door that can be easily operated with one hand, and shall have an internal drain board allowing lid closure or an external drain facility if the internal option is not practical. The unit shall have a permanently attached conspicuous label summarizing the operating requirements. [OAC 252:100-39-42(a)(1)]
 - 2. Operating requirements. All clean parts shall drain for at least 15 seconds or until dripping ceases before removal, the degreaser cover shall be closed when not handling parts, and VOC shall be sprayed only in a solid fluid stream, not in an atomized spray. Waste VOC shall be stored in covered containers and waste VOC shall not be handled in such a manner that more than 20% by weight can evaporate. [OAC 252:100-39-42(a)(2)]
 - 3. If the VOC used has vapor pressure greater than 0.6 psia or if the VOC is heated to 248 °F, the unit requires additional control. Such control shall be a freeboard with ratio at least 0.7, a water cover where the VOC is insoluble in and denser than water, or another system of equivalent control as approved by the AQD Director. [OAC 252:100-39-42(a)(3)]

- f. A startup, shutdown, and malfunction plan has been prepared in compliance with 40 CFR 63 Subpart A. The current plan shall be retained for the life of the facility and superseded versions of the plan shall be retained for five years after the date of revision. Both current and retained versions shall be readily available for review. [40 CFR 63.6(e)(3)]
- g. VOC storage vessels greater than 40,000 gallons in capacity and storing a liquid with vapor pressure greater than 1.5 psia shall be pressure vessels or shall be equipped with one of several vapor loss control systems. [OAC 252:100-37-15(a)]
- h. Activities at EUG 18 have established that HRMT is subject to 40 CFR 63 Subpart GGGGG. Any and all other activities at HRMT that are “site remediations” as defined in §63.7957 and satisfy the requirements of §63.7881(a), unless otherwise exempted, shall comply with any applicable requirements, including, but not limited to: §63.7880 - 7883 What This Subpart Covers
 - 1. § 63.7884 - 7888 General Standards
 - 2. § 63.7890 - 7893 Process Vents
 - 3. § 63.7895 - 7898 Tanks
 - 4. § 63.7900 - 7903 Containers
 - 5. § 63.7920 - 7922 Equipment Leaks
 - 6. § 63.7935 - 7938 General Compliance Requirements
 - 7. § 63.7950 - 7953 Notifications, Reports, and Recordkeeping
 - 8. § 63.7955 - 7957 Other Requirements and Information
 - 9. The permittee shall comply with the provisions of 40 CFR 63 Subpart A as specified in Appendix to Subpart GGGGG, Table 3.

SPECIFIC CONDITION 3

- a. No later than 30 days after each anniversary date of the issuance of the initial Title V permit (September 1, 2002), the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, certification of compliance with the terms and conditions of this permit. [OAC 252:100-8-6 (c)(5)(A) & (D)]
- b. Alternatively, the facility may submit an additional compliance report covering the period of September 1 to December 31, and thereafter submit certifications of compliance for the period of January 1 to December 31. All reports are due 30 days following the period which is covered by the report.

SPECIFIC CONDITION 4

Construction Permit No. 2007-005-C (M-1) and Construction Permit No. 2007-005-C (M-13) will remain in effect.

SPECIFIC CONDITION 5

The Permit Shield (Standard Conditions, Section VI) is extended to the following requirements that have been determined to be inapplicable to this facility. [OAC 252:100-8-6(d)(2)]

OAC 252:100-7	Minor Sources	not in source category
OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-47	Municipal Solid Waste Landfills	not in source category

SPECIFIC CONDITION 6

Within 180 days following commencement of operations of each new or modified heater authorized by this permit, performance testing shall be conducted and a written report of results submitted to AQD documenting compliance with emissions limitations by each new or modified heater. The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality: [OAC 252:100-43]

- Method 1: Sample and Velocity Traverses for Stationary Sources
- Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate
- Method 3: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight
- Method 4: Moisture in Stack Gases.
- Method 5: Filterable PM Emissions from Stationary Sources
- Method 6C: SO₂ Emissions from Stationary Sources
- Method 7E: NO_x Emissions from Stationary Sources
- Method 10: Carbon Monoxide Emissions from Stationary Sources
- Method 25A: VOC Emissions from Stationary Sources
- Method 202: Condensable PM Emissions from Stationary Sources

A copy of the test plan shall be provided to AQD at least 30 days prior to each test date.

Performance testing shall be conducted while the heater is operating within 10% of the rate at which operating permit authorization will be sought.

At least 30 days prior to the testing, a notification of the test date and testing protocol shall be submitted to AQD. Deficiencies in the protocol shall be resolved prior to commencement of testing.

SPECIFIC CONDITION 7

Within 180 days following commencement of operations of any new or modified heater authorized by this permit, performance testing shall be conducted on the existing heaters taking PM_{2.5} limits and a written report of results submitted to AQD. The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality:[OAC 252:100-43]

Method 1:	Sample and Velocity Traverses for Stationary Sources
Method 2:	Determination of Stack Gas Velocity and Volumetric Flow Rate
Method 3:	Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight
Method 4:	Moisture in Stack Gases.
Method 5:	Particulate Matter Emissions from Stationary Sources
Method 7E:	NO _x Emissions from Stationary Sources
Method 10:	CO Emissions from Stationary Sources
Method 25A:	VOC Emissions from Stationary Sources
Method 202:	Condensable PM Emissions from Stationary Sources

A copy of the test plan shall be provided to AQD at least 30 days prior to each test date.

Performance testing shall be conducted while the existing heater is operating within 10% of the rates at which operating permit authorization will be sought.

At least 30 days prior to the testing, a notification of the test date and testing protocol shall be submitted to AQD. Deficiencies in the protocol shall be resolved prior to commencement of testing.

SPECIFIC CONDITION 8

New tanks will be added to the East Refinery, but the final designs are not yet ready. As an interim measure, a limit of 1.20 TPY VOC (which includes roof landing emissions, if any) from the new tanks will be established.

SPECIFIC CONDITION 9

The permittee shall apply for a modified operating permit within 180 days of start-up of any new unit authorized under this construction permit.

SPECIFIC CONDITION 10

The permittee shall keep records of actual emissions and comparisons to Baseline Actual Emissions for as required by OAC 252:100-36.2(c). These records shall be made available upon request.

SPECIFIC CONDITION 11

As part of the operating permit application, the permittee shall submit maximum anticipated throughputs and resultant VOC emissions for the organic liquids storage tanks in EUG-3 and EUG-20. [OAC 252:100-8-6]

**MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(July 21, 2009)**

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.

[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements. [OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F. [OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:

- (1) the date, place and time of sampling or measurement;
- (2) the date or dates analyses were performed;
- (3) the company or entity which performed the analyses;
- (4) the analytical techniques or methods used;
- (5) the results of such analyses; and
- (6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report.

[OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions.

[OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act.

[OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants ("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other

information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.

[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM₁₀). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.

[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."
[OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.

[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification.
[OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit.
[OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.

[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby. [OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege. [OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit. [OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment. [OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.

[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances:

[OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

- (1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
- (2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
- (3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
- (4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d).

[OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.

[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited.

[OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

- (1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
- (2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
- (3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
- (4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance.

[OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

[OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that:

[OAC 252:100-8-6 (e)(2)]

- (1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
- (2) the permitted facility was at the time being properly operated;
- (3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof.

[OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.

[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

- (1) 5 tons per year of any one criteria pollutant.
- (2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.

[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.

[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

- (1) result in no net emissions increases,
- (2) are not modifications under any provision of Title I of the federal Clean Air Act, and
- (3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions,

and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

- (1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
- (2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]
- (3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]
 - (a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
 - (b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
 - (c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
 - (d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.
- (4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]
- (5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]
- (6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]
- (7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

- (1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
- (2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
- (3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC” as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

- (1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
- (2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;
- (3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
- (4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
- (5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
- (6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source’s Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

- (1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
- (2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
- (3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).
- (4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R. § 70.8(a) and (c).
- (5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
- (6) The DEQ complies with 40 C.F.R. § 70.8(d).
- (7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).
- (8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.
- (9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).
- (10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]

Anthony Conetta, Refinery Manager
Holly Refining & Marketing – Tulsa, LLC
1700 S. Union Avenue
Tulsa, OK 74107

Re: Part 70 Permit No. **2012-1062-C (M-1)(PSD)**
Tulsa Refinery

Dear Mr. Conetta:

Enclosed is the renewed Title V permit authorizing operation of the referenced facility. Please note that this permit is issued subject to certain standard and specific conditions that are attached.

Also note that you are required to annually submit an emission inventory for this facility. An emission inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or submittal process should be referred to the Emission Inventory Staff at 405-702-4100.

Thank you for your cooperation in this matter. If we may be of further service, please contact our office at (918) 293-1600. Air Quality personnel are located in the DEQ Regional Office at Tulsa, 3105 E. Skelly Drive, Suite 200, Tulsa, OK, 74105.

Sincerely,

David S. Schutz, P.E.
New Source Permits Section
Air Quality Division



PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 N. ROBINSON, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 2012-1062-C (M-1)(PSD)

Holly Refining & Marketing – Tulsa, LLC,

having complied with the requirements of the law, is hereby granted permission to operate the Tulsa Refinery (East), 902 W. 25th Street, Tulsa, Tulsa County, Oklahoma, subject to standard conditions dated July 21, 2009, and specific conditions, both attached.

In the absence of commencement of construction, this permit shall expire 18 months from the date below, except as authorized under Section VIII of the Standard Conditions.

Division Director

Air Quality Division

Date